BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

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IN THE MATTER OF: : Docket Number

REGIONAL TRANSMISSION ORGANIZATIONS (RTO): RM01-12-000

ELECTRICITY MARKET DESIGN AND STRUCTURE :

- -x

Committee Meeting Room

Federal Energy Regulatory

Commission

888 First Street, NE

Washington, DC

Wednesday, February 6, 2002

The above-entitled matter came on for workshop, pursuant to notice, at 10:15 a.m., Dave Mead and Alice Fernandez, Moderators, presiding.

BEFORE COMMISSIONERS:

CHAIRMAN PAT WOOD, III

COMMISSIONER WILLIAM L. MASSEY

COMMISSIONER LINDA KEY BREATHITT

COMMISSIONER NORA MEAD BROWNELL

APPEARANCES:

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ALISON SILVERSTEIN, Chairman's Office

ON BEHALF OF PANEL 3:

ALEX GALATIC

Strategic Energy

ROY SHANKER

PhD

JOHN HANGER

President, Citizens for Pennsylvania's Future

LORENZO KRISTOV

California ISO

-- continued --

APPEARANCES (Continued):

STEPHEN G. WARD

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JOHN O'NEAL

President, Mirant Mid-Atlantic

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-- continued --

APPEARANCES (Continued):

ON BEHALF OF PANEL 4:

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APPEARANCES (Continued):

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P R O C E E D I N G S

MS. FERNANDEZ: I'd like to welcome you to the second day of our RTO conference. I think we had a very interesting day yesterday, talking about energy markets and transmission rights and financial rights.

Today, in the morning, we're going to move on to another topic that I hope we will also have a fairly lively debate -- it's one of those topics I'm sure we will -- that is on generation adequacy. Dave Mead is going to be the moderator of today's panel.

One kind of general request I have, I think it would be helpful -- we found yesterday that sometimes people were using terms that not everyone understood or may have been using them to mean slightly different things. I think it would be helpful, when people are talking about in the ICAP, and generation adequacy, firm contracts, those types of things, if people sort of define what they mean so we can at least be sure we're talking with the -- when we're having differences of opinion, that they're not differences just because we're calling things differently.

In terms of the schedule, we're going to follow the same basic routine we did yesterday. We're going to break around 12:30, and we are going to try and allow some time for audience questions.

With that, I am going to turn over to Dave, who is the moderator of this panel.

MR. MEAD: Good morning. I'm an economist in the office of markets, tariffs and receipts here at the Commission. We're here this morning to talk about long-term generation capacity adequacy. And this is an issue that the Staff concept paper did not reach firm conclusions or recommendations about, rather, we posed a number of questions. So on this topic in particular, we are in particular need of the public's input.

For that purpose, we posed to the panelists in advance a number of questions that we'd like them to consider to talk about this morning. If I could just summarize the basic set of questions that we're interested in, the first one is sort of the fundamental one, and that is, is there a need to impose, upon load-serving entities, a long-term generation capacity obligation; or alternatively, can we rely on the market and market prices to elicit an adequate amount of generation in the long run.

There are a couple of concerns if we did create that obligation. Is there a problem with market power that might arise, and if so, is there a way to adequately mitigate that market power. A related question is do capacity reserve obligations inhibit competition for retail service. On the other hand, if we do impose that kind of obligation, is this a transitional issue, is this something that could go away once we have adequate demand response, or is it something that ought to remain as a more permanent sort of feature.

If a capacity requirement is needed, what form should it take. What characteristic should the resources have and that sort of thing. What should be the role of the FERC, the States of the load-serving entities, and the. Should a capacity obligation be standardized among all regions, or can the obligation be allowed to differ among regions. And finally, should there be an organized market to trade capacity obligations.

These are the kind of issues that are very important to us, and I am hoping to hear from the panel about.

So we will use the same format as we did yesterday. There will be brief opening statements from each of the panelists, no more than three minutes, and we will proceed with questions, and hopefully, at the end have a little time left for questions from the audience.

Why don't we begin again at the left side of the panel with Alex Galatic.

MR. GALATIC: Thank you. I am interested -- I'm glad to hear that you're interested in the termination -- the terminology, defining the terms here, because people, I think that's part of the problem that, our industry is kind of stuck in paradigm of terminology that was developed for a market that was cost-based back before any restructuring of the wholesale markets occurred.

Under cost-based pricing, we essentially had two products, firm energy and nonfirm energy. Firm energy was based on the total cost of production. Nonfirm was based on the variable costs of production. And the difference, the fixed cost, was labeled by the industry as capacity.

We had a big change with the introduction of market-based rates, because nobody's willing to buy nonfirm energy anymore. I doubt if any has been transacted for the last five years because it's too risky.

If you buy nonfirm energy, the seller essentially has the right to call the power back. And nobody buying, and generally selling, either to retail customers or to a wholesale counterparty, can take the risk that the seller is going to recall that energy.

So people only buy firm energy, but because it's not cost-based justification to FERC any longer, there is no need to say these are the fixed costs, these are the variable costs. There's no need to have the terminology of capacity and energy in a firm energy contract, even though before deregulation, firm essentially became known as energy plus capacity in the market-based world.

Firm energy is firm. It is only valuable because there is an assurance of delivery, and that assurance of delivery is backed by potentially severe financial consequences on the seller for nonperformance.

So we have a system now where capacity is included in the term of a firm energy contract, in the concept and in the price. Because without that assurance of delivery, people were buying nonfirm energy, and the price would be around -- close to zero. It essentially has no value without the assurance of delivery.

Now, in some areas of the country, particularly in the Northeast, people are still calling firm energy "energy only contracts," "energy only markets." This clearly does not recognize that the capacity component is embedded in a firm energy contract. So some ISOs have required people to buy capacity credits. They say it's a capacity payment.

A lot of people think whenever -- I read in the paper, in the, you know, Reuters News that goes into the general press, that installed capacity is -- gives people rights to supply.

Installed capacity does not necessarily give people rights to supply. Installed capacity credits, as they operate in the Northeast, give people the opportunity to avoid paying a penalty for not having the credits. It's more like a get out of jail free card than rights to energy supply. Any attempt to extract the component of capacity from the firm energy contract can't affect the price, the value of the firm energy contract.

So in effect, if you have, say, a firm energy contract for $40, and you say okay, we're going to make a capacity payment of $20, then the firm energy contract price remains $40 and all you've done is added a $20 application. So it ends up being more of a surcharge than anything that affects the price of firm energy, which is dependent upon supply and demand in the marketplace.

Should there be a supply obligation, a capacity obligation, you define that with energy contracts? If so, maybe it would be prudent to have a firm supply obligation.

I think, though, you'll find, if you checked with retailers around the country that have not been prohibited from buying in the forward market, that probably 100 percent of them have covered most of what they need for the summertime. At the same time, if you check with the wholesalers, probably 100 percent of them have not sold short for the summertime.

So there's a question, to try to avoid the situation we had in California where utilities and load-serving entities were prevented from buying in the forward market, then the question becomes is obligating, mandating purchasing in the forward market necessary, because most people are doing -- are buying in the forward market now anyway. And if you mandate it, then you can open up a whole new can of worms, a whole new set of unintended consequences that you might not have anticipated that may not be necessary anyway.

Thank you.

MR. SHANKER: Hi. My name is Roy Shanker. I'm a consultant. I represent a number of clients who are participating in these proceedings, but as usual, today, the comments are mine and reflect my positions. For the record, for David's questions, the first three are the most important. So there's a clear answer: yes, no, yes. Must there be a long-term capacity obligation? The answer is in theory, no. Adequacy markets aren't needed. An energy-only market is sufficient.

However, this would require some sort of rational, knowledgeable buyers and sellers with fully inelastic, reasonably inelastic supply and demand curves. There'd be no barriers to entry, and most important, no regulatory intervention that prevents the market from clearing, no price caps, no mandatory reliability requirements, no intervention that says oops, I don't like the prices today so we're going to change the rules. Realistically, none of those conditions are met.

What does it mean? Particularly, it means that we don't appear to have the political will to see high prices and to see high prices for long durations, something that is a very likely event to occur in a reasonable business cycle for high-priced capital-intensive goods in a straight commodity market.

We see this in all other sorts of commodity markets. It is typical. It is not unusual. But we know as a fact, the reality is we won't tolerate it here.

If the fundamentals of a competitive marketplace mean we're going to get something that is politically unacceptable, we know that the price is going to see price caps or mandated, formal capacity adequacy criteria. If that is going to be the result, you've got to design the market around it.

That's the reality. It's something we have to deal with, and sticking your head in the ground until a problem occurs is just simply not fair to the market participants.

The question then becomes if we are going to have some sort of price caps and we're going to mandate some sorts of capacity adequacy criteria, both of which have the effect of suppressing prices, reducing volatility, keeping the market long, we have to have another mechanism to make up the market-clearing revenues that are not allowed to be seen in the price-clearing of the electricity. And the word for that is ICAP capacity markets, whatever you want.

There has to be some sort of a residual pool of money that allows market participants to collect the shortfall that is based on the social tax that's been imposed by forcing the markets to be long. It's a reasonable social objective, but you have to deal with the consequences.

Is it a transitional issue? The answer is no. Again, in theory, I think I could design a process that could fade away, but the reality is that most of the market mechanisms that we put in place have long-term consequences. In a system like PJM where you are forcing people to purchase long-term physical rights associated with capacity, injection rights, forcing them to make 30-year investments in upgrades to the transmission system.

And it's simply not realistic to say you have those rights, I'm going to give them to you, you have to buy them, this is what's necessary to participate in the market. And somewhere down the road those rights are going to be worthless.

Further, if you look at it from the perspective of trying to achieve the goal, which is to suppress prices and keep them -- reduce the volatility, it works in a self-defeating manner. Generators aren't going to build into a market where, at some unknown point in the future, the market is going to have been forced to be long up until someone raises their hand and says it doesn't have to be long anymore. And load is not going to enter into long-term obligations where somewhere down the line somebody's going to say you don't need that obligation anymore, and there will be a surplus in the market. It simply doesn't work. You can't back out of it.

The best way to look at this whole process is to see this as a tax. We're meeting a social good. We're taxing the entire system, and we get all of the good and bad news that go with taxes. People don't like to do it. We're going to make them do it. We want a fair and equitable process over the long haul that distributes the cost of the taxes and the benefits of the taxes and the consequences of the taxes to all the market participants.

What form should the market take? There's lots of ways to do this. There are a number of designs. It could be a locational design like in New York. It could be a deliverability, sort of open market design like PJM.

I have three or four alternatives. If we have time, I can go through different paradigms that can work. I'm pretty comfortable that they do work. I don't think we want to do it now.

What needs to be understood by the Commission is that these designs don't exist in a vacuum. They are integral with the energy markets. They must be taken as a package. They must be seen to interact with energy markets. They have to be coordinated. They have to have -- there's logical consequences that come out of doing this in both markets, and you've got to match them up.

And I think the other thing to recognize, my way of thinking, what we see now in the Northeast is close, but none of the markets are properly designed, and a lot of the problems you're seeing is not because there's an adequacy market but because there is a badly designed adequacy market.

What are major elements that should be in these kinds of markets? The most important that's overlooked and is the source of the biggest flaw in all the markets designed is the time step.

You simply cannot have long-term capital assets where the reliability planning is based on sometimes as long as 24-month maintenance cycles, which is a key issue, and we can talk about that later, and where the time for new entry is between 24 and 36 months and talk about a daily market.

You'd never get to see marginal costs in that context. Marginal costs in a daily market for fixed capital goods is your own. So we're either going to see zero prices or very high prices when we're short.

What you want is a time step long enough to fulfill the tax objective, which is reduce volatility, have capital adequacy. It means long-term obligations, a long-term market step. There's no way out of this. New York has monthly markets. It's wrong. PJM had daily markets and moved to three seasonal markets. It's much too short.

One other major component is that this is a tax. It's not voluntary. People don't want to do it. So we need enforcement mechanisms. Enforcement mechanisms need to have teeth.

The historic enforcement mechanisms are almost okay in New York. They've been diluted because of the monthly markets. So they're really not okay now, and they're far, far too low in PJM. You simply can't force people to pay long-term 30-year levelized prize prices as a penalty and then zero when the market is long.

If you think it through, that's an irrational pricing concept. No one would ever buy into that market and hedge themselves. They'd always end up paying longer than 8 long-term costs by sitting there doing nothing.

We have to have performance mechanisms. There has to be property rights. A key element in some of the market designs, such as PJM, is you link what is going on with the transmission system. If you do this, you must link the capacity-related actions to property rights in the transmission system and in the energy markets.

This means incremental FTRs, to the extent they're created means incremental deliverability rights to the extent they're created, and you have to have a consistent fashion of estimating what these are and transferring them to the people who pay for it.

There was a question about should it be forecast or not. I think I'm personally more comfortable with a forecast system for the obligation. One of the things that comes out of this view of the world as a long-term tax structure is it may be reasonable -- and I keep hedging closer to this -- to look at central procurement.

It doesn't mean the ISO takes a position in the market. It may mean the ISO or RTO implements long-term procurement on behalf of the members. If we go to a structure like that, a forecast structure works very good, very well, and it also has the benefit as it keeps retail access trivial.

Certainly, you can have bilateral contracts, you implement them as contracts for differences, but you get an overall market clearing. You allocate those costs on, say, peak load, whatever manner you think is equitable, and then it really doesn't matter how retail access moves around.

It's a very simple system, and one of the nice things is, by having a longer market structure, you see long-term marginal costs. You have much less vulnerability to market power concerns. You never get rid of them entirely, but the market's more transparent. You really see marginal costs, and you have a very simple market design. So I'm edging over to long-term central procurement, although there's part of me that's still reluctant about that.

What should be the role of FERC or the states? I think it's fairly straightforward. We see this isn't a controversial area. There seems to be rough consensus on one day in 10 as standard nationwide planning criteria. Converting that into reserve margins is reasonably straightforward, a lot of work but not that difficult. I don't think we really need to mess with that part of the market.

Can it differ by regions? Yes, it can differ by regions, as long as you have enforcement mechanisms that don't allow people to lean on each other. If you can shed load by control area, something that has been set up in the PJM and PJM West structure, you can have slightly different reliability criteria, which they will have.

As long as, when trouble occurs and someone is truly physically short, you can point to at least the control area that's short and say you've got a lower reserve margin, you shed load, there's no reason not to do it.

Does this create a potential for market power? Having this market does not create a potential for market power any more than any other market creates a potential for market power. If there's high concentrations, there is the potential for market power, and market design may make it easier to exert market power, and that's something we should all be aware of.

But inherently the existence of a capacity market has no problems with market power, and in fact, moving to longer-term obligations with more rational pricing will make it a lot easier and a lot more transparent still, from a market mitigation perspective.

To the extent there is a problem with concentration, it will be easier for the Commission to take action.

Then the last statement is do these markets inhibit retail access and retail competition? No. The problems that I have seen basically have been bad business decisions, and to some extent, bad market designs, failure to hedge. If we improve the market design, certainly something as simpleminded as a long-term centralized procurement, retail access, and retail competition will become almost trivial.

Thank you.

MR. HANGER: Thank you. My name is John Hanger. I'm president of Citizens for Pennsylvania's Future.

I've just got some preliminary responses. I will reserve comments about the questions until later.

On January 19, 1994, I had the unfortunate responsibility of calling the chief of staff to Governor Casey to inform him that I thought there were rolling blackouts rippling through the PJM system. We had not gotten any word from PJM itself but we were getting calls indicating the lights were going out across Pennsylvania. And I also requested the governor to issue a state of emergency in order to encourage consumers to spur conservation and create a significant amount of demand reduction. So I think it should be said I take reliability very, very seriously.

Despite that experience, I've become a critic of capacity obligations, or ICAP, at least as defined and practiced by PJM. ICAP within PJM did not prevent rolling blackouts that day, and perhaps coincidentally, there were no rolling blackouts in one-third of Pennsylvania that had no ICAP requirement but essentially operated under the ECAR rules. So lights stayed on in Pittsburgh, went out in Philadelphia. There is no ICAP requirement, as I said, in those parts of the state where the lights stayed on.

This tale reminds me of something simple. It's delivered energy that keeps the lights on. Capacity, you can have all the installed capacity in the world, all the capacity credits, but if there isn't delivered energy, the lights are going to go out.

ICAP has not been shown, at least as practiced within PJM, to reduce the loss of load probability over other alternatives. ICAP is not encouraging more generation in PJM. Yet, ICAP rules -- or versions of ICAP rules are plainly expensive to consumers, and the question becomes what are they getting for their money.

In the Duquesne service territory, which is going to apparently become a part of PJM west, it has been estimated to meet the PJM West ACAP requirement that is, again, different from the PJM ICAP requirement in some important respects, and in my view, less onerous but still flawed. It's going to cost consumers $40 million per year to satisfy this new ACAP requirement.

Now, if PJM West could tell consumers that the loss of load probability, in fact, had declined or in some other way their adequacy of generation was assured by this new $40 million payment, over and above the 30 years' prior experience, perhaps consumers in the Duquesne service territory would be less concerned about this charge. But nobody has demonstrated they're getting anything for this $40 million. Clearly somebody is getting it, but what are consumers getting for it.

Moreover, PJM rules have been plainly dysfunctional. I think even Phil Harris would agree. He's constantly modified them over the last few years. He's always fiddling with them. There's always problems.

Some of the problems, in fact, include the law of unintended consequences. According to the market monitoring unit in the summer of 2000, the way the market, ICAP market worked, it may well have endangered reliability itself, because it created economic incentives to, in fact, move energy out of PJM.

The market has been subject to withholding. There are clear problems with market power within the ICAP market, this is not PennFuture alone saying things. My point being is some utilities are saying this, within PJM.

We've seen weird patterns on pricing. When energy prices are very low, ICAP prices have gone through the roof. So energy price is signaling the lights are secure, supply is bountiful. The ICAP price, nonetheless, is signaling the reverse, that the lights are on the verge of going out and there's real scarcity.

It's interesting that many proponents of ICAP requirements within PJM, despite what they may tell you down here, within PJM's councils, oppose vigorously demand response programs. Indeed, only one owner of generation voted for an economic demand response program within PJM, and that was Mission Energy, to its credit.

All the rest, however, have fought demand response programs, as well as insisting on maintaining ICAP requirements. The reason -- one of the principal reasons that the ICAP requirement that has been modified to now three seasonal periods, is because it was, again, resisted by many of the owners of generation to have longer periods.

So the question becomes what do you replace ICAP with, because you must have generation adequacy measures. And there are clearly alternatives that would be cheaper, and in fact, more effective in ensuring that delivered energy is, in fact, there for consumers and the lights stay on. And the alternatives are the creation of operating reserve markets, forward markets, and I believe they ought to be long-term markets, including up to two years. Perhaps they have to be administered or established by the RTOs in the first instance.

Beyond that, demand response has to be negotiable, and it is very troubling that really demand response faces substantial opposition from the capacity owners, at least within PJM, and I suspect, in other parts of the country.

If we get proper demand response, you don't need certainly the PJM ICAP program, and indeed, Phil Harris has told me that many a time, and I'm sure he's told you that.

So why don't we have it? Why are we having this debate? Why don't we focus on the real alternatives? The bottom line, however, is we don't have it and won't have it, I believe, unless FERC makes it happen.

And I wanted to thank you, Commissioners, for being visionary and also being strong. And it's my pleasure to be here today.

MR. KRISTOV: Good morning, Commissioners, members of the panel. My name is Lorenzo Kristov, manager of market design with the California ISO.

In California, we've been struggling with the capacity adequacy issue for a while now. As you know, on the record, we had submitted reply comments to the Staff's discussion paper last October, at which time we came out with the conclusion that it was necessary to assign a responsibility for ensuring capacity adequacy. As we look back at the root causes of California's crisis, one of them clearly was the failure of the original design to make it clear who was responsible to ensure adequate capacity.

It started out with a traditional obligation to serve on utilities, and then as we made the transition to the new market design, this was weakened and converted into simply an obligation to procure energy, which was supposed to go primarily through the power exchange, which was a short-term market.

So with limitations on how much the load-serving entities could procure on a going-forward basis, we had very high exposure to spot prices, extreme volatility in those markets. And no party really had a responsibility to ensure supply adequacy that ultimately reverted to the ISO and in large measure to real-time, where we were continuously faced with undesirable choices to either scramble to find resources at the last minute to meet obligations of high prices or to have rolling blackouts, neither of which anyone liked very much.

So in thinking about how to move forward and what to do about this and what sort of redesigns to develop, we're in the process of thinking through those issues in a comprehensive manner. One of the fundamental pieces is to redefine the responsibility and clearly reassign it to ensure that capacity is adequate. And some sort of capacity obligation is the mechanism we're focusing on. We have a ways to go yet in determining what the details of that obligation should be.

There are a few things I can say about it, thinking about it. One, we definitely agree with the initial observations that Staff put out in their paper; that having limited demand response is a difficulty, as well as the inability to target rolling blackouts, specifically to the customers of deficient load-serving entities.

If it were, perhaps, in an ideal world, as Mr. Shanker pointed out, where you can meet a number of theoretically optimal conditions, it may be possible to not have some sort of an obligation where you can focus the rolling blackouts, should they come, specifically on the customers who choose to be blacked out by accepting a lower level of reliability.

Right now we can't do that, and I think there's a lot of things that get in the way of achieving the optimal conditions. So for the foreseeable future, we see it's necessary to redefine this obligation, and we're thinking in terms of a number of basic design obligations that should be included, recognizing also that we don't see a model that's working elsewhere that is a perfect one to emulate.

Whereas in yesterday's discussion, we talked a lot about how PJM does forward congestion management and locational marginal pricing, and we see there's an algorithm there that has a lot of logical appeal and is also working in real life. We don't see clearly a design for a capacity obligation or a capacity market that we can say yes, this is the right model. Plus, there are California's unique situations. In some ways, we are highly dependent upon them. We expect to be for the foreseeable future. So we don't have the kind of internal capacity margins that some of the others have.

With that in mind, we're thinking about a few basic design parameters which I'll talk about, and then I'll continue discussing some of this in the question and answer discussion.

For one, the capacity obligation we're thinking about, we're calling available capacity or ACAP, and that availability means that resources designated as available capacity resources have a responsibility, a requirement to appear in the ISO's markets on a daily basis, through either forward energy schedules, through bids that we can dispatch in ancillary service markets, through a unit commitment. And if the ISO doesn't select them in any of those day-ahead markets, they still need to be there in real-time to be called upon if necessary.

The availability notion would place responsibility for forced outages on the suppliers, and essentially, as the load-serving entity meets its obligation on some forward basis, whether that's monthly or seasonal or even a longer time period, or some combination, it identifies the suppliers of that capacity, but then on a daily basis, it's up to the designated suppliers to come through with appearing in the markets being scheduled, and then delivering and following dispatch instructions on the day.

The load-serving entity would be allowed to meet its obligation through a combination of its own generating resources, QF contracts, firm energy contracts, demand responsiveness, different types of capacity-only contracts or call options. We recognize there's some algorithms or formulas to be worked out. We want to enable the full range of existing portfolios in California's markets today to be able to count towards meeting an obligation with minimizing double payments and also relying on what's there. In the near term, for example, there is a substantial portfolio of energy contracts that should be able to satisfy this need.

The ISO, then, is contemplating defining the obligation on load-serving entities to be demonstrated on a longer-term basis, at the very least on a monthly basis before the start of the month, or perhaps on a multimonth or seasonal basis, but then that obligation would roll over to the supplier on a daily basis for compliance.

Finally, we're looking at ways to build in a deliverability requirement so that if some of this capacity is provided through imports, the deliverability of it is assured. Or if it's applied to resources internally, and there may be transmission constraints that limit the full capacity of those internal resources from being delivered at one time, that needs to be taken into account, into how the capacity of the resources counted toward the obligation.

Similarly, we have locational requirements in some areas of the ISO grid areas where a minimum quantity of internal generation in those areas has to be provided to support the local load, and so some regional or some locational aspect to the obligation will probably be necessary to ensure that we have local reliability as well.

I think at that point I will stop my comments and get on to the questions later. Thanks.

MR. WARD: I'm Steve Ward from Maine, and I serve as public advocate in the state of Maine and president of NASUCA. I want to make some general, 30,000-foot-type comments.

It seems to me that the question about how the capacity mechanism is designed and the need, in fact, for a capacity mechanism is going to depend on three factors anyway, and we've heard about some of this already.

One of the factors is the willingness of customers to accept significant price increases or price volatility in manager markets. New England historically has had relatively low, certainly not expensive, ICAP charges, during a period in which a great deal of generation was brought on line. In my state, 1500 megawatts; in the entire region, 4000 megawatts, another 6000 megawatts coming on line in the near future.

But the trade-off for that was a $6000 per megawatt-hour day when prices hit, that volatility, and customers were exposed to that kind of a price shock.

Since that time, there has been in place a $1000 a megawatt-hour cap. So one trade-off is is there a willingness to accept infrequent but severe price shocks in conjunction with an incentive for supply of generation? And if there is not, in my view, a $1000 megawatt-hour price cap is a reasonable choice. Then what is the capacity mechanism that needs to be designed?

A second factor to consider is the demand response. When customers do have an ability to reduce consumption in direct response to price, that disciplines the market. I don't see that happening in a fashion that could entirely replace the need for a capacity mechanism, a deficiency charge or bilateral arrangements.

Today, in New England, there is a demand response when the market reaches something like $200 a megawatt-hour. At that point, customers find ways of reducing load, find ways of responding to the price. At lower levels for capacity, that's not the case, but it's clear that we'll all be better off if we develop more experience with demand response mechanisms.

The third factor that I wanted to talk about hasn't been mentioned. New England has had a fairly liberal, straightforward, uncomplicated minimum set of standards for new generators. This has facilitated the arrival of new generators on the grid. New England, of course, is a region with lots of divested, no longer vertically integrated utilities.

It strikes me that is a third factor worth thinking about when you decide how you want to stimulate, in the long term, new generates on the system. I don't vote for efforts to create a market mechanism or to rely solely on a market mechanism for capacity responsibility. I think it's real tough, as has already been pointed out, to find ways of creating a market for something that has zero short-term marginal cost.

It makes more sense, to me, to structure something like an administrative fee. My analogy is if you want to take your trash to the dump, in addition to a per-bag charge for the trash, you probably ought to go to the town hall and pick up a sticker so that you make that payment on a regular basis for the right to take trash to the dump.

My last point, let's be very careful about overcollecting. There are huge impacts on the market that result from a shift from -- well, in New England's case, 17 cents a KW month to potentially 8.75 cents a KW month. Those shifts dwarf all the benefits that have been identified from the formation of the northeast RTO in terms of annual impacts on consumers. So we have to be very careful that in our effort to do something that we think is theoretically necessary we don't clobber consumers.

Thank you. I'm very grateful for the

invitation to speak today.

MR. O'NEAL: Good morning. My name is John O'Neal, president of Mirant's business unit.

I guess I'd like to begin by advancing Mirant's belief that a full-term capacity requirement should be a part of the Commission's standard market design. And I have just three quick comments or points in support of that concept, and I'll leave most of my other comments to the Q and A.

We believe that a well-designed RTO capacity requirement ensures capacity for consumers and restrains market power by requiring generators to bid into day-ahead energy markets and requiring them to preschedule maintenance outages.

Two, we believe that RTOs should include demand response options in capacity proposals to the Commission. More specifically, we believe that load-serving entities should have the ability to meet their capacity requirements through either self-generation, through firm contracts with verifiable capacity resources, or through similarly verifiable load curtailment contracts.

And three, we believe that a well-designed capacity requirement is in the best interest of consumers and will not inhibit retail competition but, instead, will increase reliability. The greatest threat, we believe, to consumers is a poorly designed or no capacity market and the resulting shortages that might occur.

Thank you. Those are my brief comments. I look forward to the Q and A.

MR. OATES: Good morning. My name is Joseph Oates. I'm from Con Ed Company in New York. I'm the vice president of the energy management group where we buy capacity, buy energy, buy gas for customers.

I'd like to talk to you about our views on the capacity market from two perspectives; one as a utility operator, and the second as a large load-serving entity.

From the utility operator perspective, generation adequacy is very important to us. And there are some who think that the supply shortage or the supply crisis in New York has eased somewhat. Yesterday's New York Times has a headline on the front page saying that the electricity crisis eases in New York, and that's not our view. We're the operator there. We don't see it that way. Having a capacity market, we believe, is very important to ensuring that this crisis is eased and that supplies do come to the market.

The other perspective we have is as a load-serving entity. Last year we spent more than three-quarters of a billion dollars on installed capacity for our customers. Although we'd like to pay less -- I think everybody would -- it's something that we think is very important to ensure, that on the hot summer day -- and we had one this past August -- there's enough iron in the ground, enough capacity to be able to meet demand. And if you don't have a capacity market, it's hard to do that. That's not going to happen.

So I have three reasons why we think an installed capacity market is important. I think the first and foremost is that they really do provide for an increased level of reliability compared to an energy-only market. In New York, a capacity obligation has been in place for a number of years, prior to restructuring, and now in the New York ISO markets.

I think I agree with some of the other folks that mentioned, in a capital-intensive industry you sometimes will have resources, in our case peaking units, that maybe aren't going to run too many hours of the year to be able to recover their costs in an energy market, and a capacity market is vital to ensure that they're there.

The second reasonable why capacity market is important is we really think they provide the forward price signal that's needed to incent companies like John's to be able to bring new capacity to the market. We also think that a market will provide a mix of resources. Our demand is a summer demand. It's very peaky, and we do rely on peaking resources.

And a capacity market, we believe, will provide us with a mix of the resources that are needed to be able to meet demand on that hot summer day. We also think it will incent people to want to build plants, and perhaps, result in additional resources being there, above the minimum reserve margins that are established for reliability reasons.

The third reason that we think capacity markets are important is we think they will moderate market volatility in energy markets, and provide generators and load-serving entities with a stable set of revenues and costs as they move forward. Energy-only markets, we think, as some of the other speakers have mentioned, will result in very volatile prices, to be able to allow generators to recover their fixed costs of operation.

So now that I told you why I think it's important, what are the three elements that we think need to be a part of any capacity market? The first thing that we think has to be there is an independent entity to develop the rules, such as what is the reserve margin and what is the locational requirement. We think that's a very important component, to make sure you have the capacity located in the right places.

The second element we think that needs to be there is for the RTO or the ISO, or whatever we're going to call it, to be there to perform administrative responsibilities. And in there, that's where you -- they calculate for each load-serving entity, what's their obligation, be it for a six-month or annual period.

I think that process will also have to include demand response. Demand response needs to be a part of any capacity requirement. The other thing about demand response is that you have to know it's going to be there on that hot summer day. It can't be something that's voluntary. The ISO, the operators need to know that there's a demand reduction out there that can be achieved in order to be able to maintain reliability.

The last thing the RTO would need to perform is a market monitoring function to really handle some of those times when you have constraints, you don't have an adequate number of suppliers in a particular market, and to make sure that consumers aren't hurt by a requirement to have capacity purchased.

And the third point is that we think it's important for the ISO to operate a voluntary capacity market. We think there should be a mix of bilateral arrangements where market participants can decide on their own price and quantity. We think it's very valuable to have a marketed clearing mechanism run by the ISO to be able to send a signal to the market, this is the value of capacity that we see going forward.

That's all my remarks. I can pick up anything else on the Q and A. Thank you.

MR. OREN: Good morning. My name is Shmuel Oren, and thanks for inviting me. I am a professor at the University of California at Berkeley, and I'm also the site director of the Power System Engineering Research Center there. And I've been doing consulting to various private and public organization on market design issues.

I agree with Roy, that in theory, unrestricted spot energy prices that reflect scarcity should provide the correct price signal for adequate generation reserves. But for various reasons, this is not practical, and some of the reasons, the energy markets are inherently very volatile, and politically, some of those price spikes are unacceptable.

Also, even -- the other reason is it's very hard to differentiate what our legitimate scarcity is and what is just high prices due to exercise of market power. And also, even if the price signal was correct, because of the lag in building capacity, there is always the issue, are we going to let high prices persist during the construction, which is going to cause tremendous transfers between consumers and producers.

So all those issues make it necessary to have some form of price mitigation or price insurance, and I like to think of capacity markets as price insurance rather than as a tax. Now, ideally, again, the market would provide such insurance, but since there is evidence, for various reasons, that it doesn't, then I think it's appropriate to have, the same way we have in automobiles, to have mandatory insurance.

Now, the question is, do capacity markets, the way they are defined today, do they fulfill this function of providing insurance against high prices. And I would argue that no. The problem with the capacity markets is that they don't entail any kind of delivery obligation or any kind of delivery price obligation. They are just disassociated. So they don't really fulfill that function.

ICAP markets are also inherently dysfunctional in the short run, because as Roy pointed out, if the time step, if you're talking about days or even a month, then the supply and demand for installed capacity is totally inelastic. So either you have too little, and the prices going to infinite; or too much and then the price goes to zero. So the time step has to be much more significant.

The alternative that I am advocating and writing in lectures is that we need to really have kind of a paradigm shift and think of capacity obligation more as a hedging obligation, that a load-serving entity should be asked -- there should be kind of a mandatory insurance requirement, asking a load-serving entity to obtain hedges, perhaps for a certain percentage above historical peak in the form of call options.

And such call options can be covered either by contracting with generators, which will have the same effect of a capacity market, by contracting with interruptible load; or for a short period of time, I would argue that we may even want to allow self-insurance, which basically would require the load-serving entity to maintain some sort of financial reserve the way insurance companies have to maintain. And they will be obliged, in case there is a shortage, to cover -- use those reserves to cover the gap and be able to buy at the $1000 a megawatt price from generators that are not in any kind of contractual obligation and should be -- and are allowed to sell at the cap.

This kind of alternative, by creating those kinds of options, that maintains the connection between capacity and energy, recognizing ultimately the purpose of capacity -- capacity has no value on its own. The purpose of capacity is really to provide an option for generating energy.

One of the things that we see in some of the capacity markets is there is a total disconnect, and sometimes we can have a scarcity of capacity, and if you impose a rigid obligation for installed capacity, that price can get very high, totally out of proportion of what the energy is at that time. So by maintaining it as an option and giving the load-serving entity a way out through self-insurance, I think that we can maintain that link.

Now, in terms of is it a transitory effect, is it something that is going to go away? Well, I think in the long run, if we have enough demand-side response and proper technology, insurance can start to become more of a private good, and people would allow -- I mean, loads would be allowed to self-insure, but in order to get to that stage, we have to get out of that mode of obligation to serve and start to recognize that what we need is obligation to serve at the price and have the technology that will allow us to exclude customers that refuse -- you know, that choose not to ensure themselves, as long as the provision of electricity is more treated as a public good, then the insurance has to be mandatory, and then we -- but I think that by using this kind of a financial approach, it's going to, first of all, be more consistent with the market philosophy, and it's going to meet the same needs that we want the capacity markets to serve.

MR. MEAD: I thank you for those comments. That was very helpful. Let's start with the first question. As I interpreted the comments of the various panelists, I heard a lot of support for the notion that the market by itself, at least right now, cannot be relied on totally to elicit the right amount of generation capacity for a number of reasons, such as regulatory price caps and so forth.

But back to the specific mechanism for this generation capacity obligation, there may be differences of opinion about what that might be. I guess the two contrary views that I heard today, I think, is most strongly in the opposite camp with Mr. Galatic, and Mr. Hanger, I heard him criticize PJM-type capacity obligations, but if I heard you correctly, at the end some notion of a forward reserve obligation or something else to supplement the main market mechanism might be needed.

Let me just stop there for a second. Have I summarized what I heard, correctly?

MR. SHANKER: I think so. If you look across the comments, I think what you're hearing is that there is some consensus that a variety of market failures are going to need some sort of intervention, and the questions are the mechanisms of how to do it.

Shmuel's comments about call options are fine. One way of looking at some of the eastern markets, although there are some other problems about time steps, you buy ICAP, you have $1000 call option. I helped draft something in Florida that had a different call option mechanism. There's a lot of ways to do it.

You can't avoid the fact that if you're not willing to accept the consequence of high prices for extended periods, even if they're totally legitimate from pure market mechanisms, no adverse manipulation, that we're going to have to do something.

One aside from that if I can throw in because I think something else has gotten mixed in here. I often here the comment that this is expensive. This is like a surcharge and a lot of extra cost, and that simply isn't true. To the extent that the adequacy requirement is a reasonable reflection of what people think the market requirement would be -- and we can argue about whether that's right or not -- long-run total costs to consumers are virtually identical.

What we've done is smooth out the cost. We've taken out the volatility. We've taken out the bumps, and we've tried to, essentially, levelize them.

What you hear people complaining about high costs are usually market design failures where people because of those failures have been getting a free ride for something of great value that they should have been paying for. The notion that suddenly this is a huge surcharge is like pretending that those capital assets were for free and sitting out there and nobody had any obligation to pay for them. This is simply wrong.

Empirically, if you wanted to be real conservative and stretch beyond what any reasonable person might have thought was the equilibrium level, let's say in something like PJM you stuck on an extra 4 percent, which would be a lot, work the numbers, and you'll see that that's about $80 million a year of extra carrying costs. If you exceeded a rational reserve target, that's what it would cost to carry about 2000 megawatts of additional peakers. That's less than an hour and a half of the problems that California had.

MS. FERNANDEZ: I think Mr. Hanger and Mr. Galatic looked like they wanted to respond.

MR. GALATIC: Thank you. If we look at the data about new construction of generation around the country, more generation is being built in regions that don't have ICAP, for the most part. In New England a lot of generations started construction when the price of ICAP was zero or essentially zero. And PJM, they're adding about 3 percent a year, at least that's what's expected by

Wall Street to actually come on-line. Other regions of the country that don't have ICAP are adding generation much faster, Texas for example.

And it's not in response to, you know, volatile wholesale prices in the spot market. It's in response to very fairly stable, relatively much more stable than in the spot market, the forward energy prices, that's driving the decision of people to build generation.

Conversely, New York City, over a billion dollars a year being spent on ICAP. In addition to what we pay, the highest price for energy in the country right now, New York last time I looked a couple days ago was $69 a megawatt per hour for summer, Midwest is 37 for the months was July and August. And that billion dollars is enough to build 1000 megawatts and completely pay for it, increasing the supply in New York City 10 percent every year, and virtually nothing is being built.

So to suggest that ICAP is encouragement for building generation, extra money that goes to generation to encourage generation, is really not borne out by the data that we see around the country about what is actually being built.

MR. HANGER: I want to -- I agree with what Alex said there. People are talking theory and dismissing theory. Fair enough. Let's look at some of the empirical experience we've had to inform this conversation.

The other point that I heard going around the room is that it is, in fact, delivered energy that keeps the lights on. Certainly in some of the ICAP markets or capacity markets, there is this disconnect between capacity and energy, and that seems to me a fundamental flaw in the design of these markets. I also heard some agreement, not from everyone but a number of people, that firm energy contracts ought to be one of the mechanisms that would count towards a so-called capacity obligation.

That's not the case in PJM right now. You could have 200 percent firm energy scheduled to serve your load, and you still have to go and meet the PJM/ICAP requirement. So I did hear some agreement, but I didn't hear any agreement frankly for a PJM-styled ICAP, and I just wanted to make that clear. I didn't hear that from the California ISO. I didn't hear that from Mirant even when the gentleman does endorse allowing firm energy to count as a possible means of meeting capacity requirement.

MR. OATES: I want to make a few comments on New York City and the capacity situation. There is interest in building new electricity generation in New York City. Is there going to be much new supply this summer? Probably not. Is there going to be new supply next summer? We hope so. And there's interest for future years. If we did not have a capacity market for the potential for a generator to be paid for having capacity located in New York City, the interest would be a lot lower than it currently is.

As far as the costs, the cost of building in New York City, as a lot of folks have found out, it's enormous. The New York Power Authority jumped through hoops last summer to get 400 megawatts of gas turbines built. They had to jump through hoops to do this in six months, but it cost them over $1000 a KW to do so. So the cost to build capacity in New York City is significant.

We don't believe energy markets alone will enable them to recoup their costs. Even at the prices they're talking now, 60-, $70 a megawatt-hour, it's just not enough. Am a complaining about what I pay? Yeah, I'd like to pay a little bit less, but do I want to do away with capacity markets? No, I don't. If we don't have them, this crisis that's out there becomes a real crisis.

COMMISSIONER WOOD: Doesn't the load-serving entity have an in, whether it's required by the regulator or not -- I guess this goes for any of the jurisdictions. Don't the load-serving entities, whether in a retail unbundled environment or regulated bundled environment, have an incentive to make sure their customers are provided for three years hence? Isn't that worth something?

MR. OATES: We don't have a three-year requirement going forward.

COMMISSIONER WOOD: But you as a licensed entity that wants to -- is your area unbundled?

MR. OATES: We have 100 percent retail choice opportunity.

COMMISSIONER WOOD: Don't you want to keep those customers?

MR. OATES: Not really. I don't make any money selling capacity or energy to my customers.

COMMISSIONER WOOD: Because you're averaging the rate?

MR. OATES: Because that's the rules in New York. Whatever my costs are, that's what the customer pays. I make nothing. So on a hot summer day when the price is real high, you know, we get phone calls complaining about prices, but I'm not making any money on that. I make money delivering the energy.

COMMISSIONER WOOD: Right. I guess I should ask your retailing arm. Mr. O'Neal, are you-all involved on the marketing side? Is anyone here a load-serving entity?

MR. GALATIC: We definitely have very strong financial incentive to buy forward, for example, and basically to buy the power, lock it up at the time that we make our retail sales. And if it's a one-year contract, we buy enough power for the next year, especially to cover the volatile summer period.

In 2000, when California utilities were prevented by rule from buying forward, we were signing up customers, 5-, 6-year contracts. You can believe we were buying on the wholesale side to lock that price in, because otherwise it's a huge gamble that no retailer can afford to take.

Buying and selling at a fixed price or, in our case a ceiling price, and not locking up the wholesale supply, because then you're putting your company at a severe financial risk that is just -- it would be ridiculously imprudent.

MR. SHANKER: One of the other things, I think, for your purposes, focusing so much on New York City may not be too constructive. Remember we started this --

COMMISSIONER WOOD: Take Chicago, take Dallas.

MR. SHANKER: We started the whole process with deregulation that the generation sector was workably competitive. We talked about setting up these kinds of markets. I was one of the people in the restructuring of New York who said I'm not sure that's a reasonable assumption for New York City, and indeed, an enormous amount of the effort of the New York ISO and all the activities in New York, probably half to three-quarters of what we do in market design is trying to fix the fact of why competition isn't workably compatible -- or the assumption is wrong.

So we have lots and lots of rules, lots of market mitigation, lots of ICAP problems, et cetera. So we can make things work there, and we're starting, every day things get better and people are resolving the problems.

But to use the fact that it costs $1000-plus to build something that costs $250 elsewhere, that's a bad world. In other major cities, there seems to be, you know, reasonable transmission substitution options and reasonable construction going on, and it doesn't seem to be a problem.

And ICAP or adequacy markets, call options, if you want to link them closer to performance, I'm all in favor. The more you link the actual performance to the energy for the adequacy, the better off you are. Those are reasonable concepts, and the issue is whether or not you're agreeing or not agreeing you want to remove the volatility in the energy markets.

Do you want to remove the 3- or 4-year cycle of building what Shmuel is talking about where there will be shortages? If you're willing to live with that, we don't have to do that.

CHAIRMAN WOOD: Even in markets like ERCOT where you've got 90 percent locked in in bilateral contracts, and you're buying the increment off a much more volatile, not-so-liquid energy market. You, as the load-serving entity have the incentive and the ability to go out and hedge even that $1000 or $1500 price volatility in that thin slice that you buy.

So don't you have an incentive to actually mitigate even this price spike environment where you get a little bit of scarcity and/or market power?

MR. SHANKER: Sure, if the prices aren't capped, and if there's not a regulatory call that people depend on to intervene and knock the prices down.

MR. OREN: Also, we have to remember that the load-serving entities have a hedge that nobody wants to think about, but that's called bankruptcy, and they're using bankruptcy as a hedge. And as we've seen in California that, option has been exercised. So by relying on that hedge, in a way, the residual risk is passed on to the customer against their will.

So, you know, insurance always looks like a waste of money, if nothing happens. And so in hindsight, you can always point to the situation where everything was kept in check and say gee, I bought insurance, my car wasn't stolen, I could have saved myself that money.

The point is you have to buy insurance when you are young and healthy, not when you are old and sick.

So I think we have to think about those, you know, capacity markets as a form of insurance, and yeah, it costs money, but that's exactly what we have to spend in order to protect ourselves against those undesired outcomes, in which case the load-serving entity can always bail out or will sink, some sort of remedy by raising rates to the public utility commissions. But ultimately, it's the customers that are bearing that risk, and we have to ask them whether they want to do that.

MR. O'NEILL: I listened carefully to what Shmuel was saying, and he has -- he first of all has the LSEs as a responsibility for the energy, unlike Roy, who I think was going to put the RTO on the hook as the counterparty for the capacity options.

MR. SHANKER: Either way.

MR. O'NEILL: I think there's a big difference because it puts the RTO into the capacity market, whereas the LSEs keep the RTO as a nonmarket player. You have either capacity call options or demand call options so that if, in fact, you're a retail supplier, you don't have to buy in the ICAP market if, in fact, your load can respond to prices.

And then in the end, I think Shmuel said that there has to be a creditworthy requirement for people who are going to buy in the RTO markets, because the price could spike. It seems to me that -- and of course, we don't have the technology today to do that, and I'd be interesting in finding out why they have opposed this in PJM.

That seems like a reasonable proposal that keeps the RTO out of the market, that keeps the responsibility, as the chairman said, with the load-serving entity, and allows them to avoid being in these ICAP markets if the demand is responsive.

MR. SHANKER: Mandatory call contracts, if you wanted to call it mandatory insurance or tax or whatever, mandatory call contracts carried by load are fine. Now, you've got to think about who can sell them. Can anybody sell them, or do you have to have hard assets to back them? We can talk about that. That's a different design element.

CHAIRMAN WOOD: This was the same issue, John, you mentioned as one of your three. What did you just call it?

MR. SHANKER: Mandatory call contract with -- one of the ways to do it that might allow a transition is to -- essentially the LSE has an obligation to enter into a mandatory call contract. The person who sells the mandatory call contract has to be able to back it with hard assets, but over time, as you get your comfort, as Shmuel was saying with the financial interests, maybe on day 1 it has to have 120 percent to sell 100 megawatts of calls, but other times --

MR. O'NEILL: The hard assets can also be demand response?

MR. SHANKER: Of course they can be demand response, always.

CHAIRMAN WOOD: You mentioned self-generation, verified load curtailment, which is the demand response, or firm contracts which would be the mandatory calls. Are those terms the same?

MR. O'NEAL: They are. The distinction I would make, when we talk about call options, a lot of people will point to financial instruments and suggest that we can rely on financial instruments only for this reliability mechanism, and I would suggest that that's dangerous.

At the end of the day, I think, for long-term capacity reserve requirements, we need to be able to point to steel on the ground. That's what we're trying to incent here is steel to get built. And to suggest we ought to rely on the financial promises or the balance sheets of companies is, to me, especially the environment we find ourselves in now, particularly dangerous.

MR. SHANKER: You want to see hard assets.

CHAIRMAN WOOD: Take the eastern interconnect, because it kind of blends between regions. Say 60,000 megawatts of load in PJM. If we have like a 15 percent reserve requirement, do we want to have that extra 9000 number be the boundary, the footprint of PJM? How do you define how far out you can go to have power on the ground in the next-door-neighbor ISO?

MR. O'NEAL: I think from our perspective, it needs to be verifiable. First of all, it needs to be able to perform, and you ought to have a test that says it can do what it says it can do. To the extent you're reaching across boundaries and pointing to an asset in a different market and counting on that as your capacity resource, it needs to be able to reform by having firm transmission that gets it into that market.

There needs to be some coordination amongst the different markets to be sure that it's not getting counted twice, so to that extent, each RTO needs to be make sure they're talking to one another.

MR. SHANKER: One of the areas where they are working and playing well with each other is -- there seems to be a rough consensus on rules that summarize just what John said.

MS. FERNANDEZ: I guess I was wondering, why do you only have to have it -- when you're talking about the hard assets, it seems like that's the type of requirement that basically says you have to go to a generator to buy it, you can't go to a marketer to buy it. I mean, I recognize you're buying from a marketer for a firm energy contract, that you're going to need some protections in there, but any type of requirement that seems to say you can only buy from one segment of the market makes me a little nervous.

MR. O'NEAL: We don't say there's just one segment. There's self-generation, curtailable load. We're not talking about energy. We're not talking about even short-term reserves. We're talking about a long-term capacity market and sending the signals that gets that capacity on the ground. You want folks who are actually going to build that steel to buy those products.

MR. OREN: I agree in the short run. In the long run, you want the assets. Over short period of time, since you don't build a generator overnight, I think having that extra flexibility of financially being able to cover shortfalls by buying, for example, electricity over a period of a month at $1000 and supplying your customers would provide the flexibility or the elasticity that will mitigate market power and capacity.

I think the problem that we're trying to avoid is to kind of smooth out the demand curve for capacity that is going to create those price spikes in capacity when there is a temporary shortage. And by allowing the load-serving entity to say at that price, I'm willing to take the risk myself and I'll have money, you know, like the way we allow people not to buy car insurance and post the bond, I think to cover the liability, I think that that will provide more flexibility and will mitigate market power and capacity.

MR. O'NEAL: I guess it goes to the time step that someone was talking about here. In the short term, I think you need to point to steel. In the longer term, perhaps you can point to financial guarantees.

MR. KRISTOW: The translation from capacity into real-time is an important piece of this. From California's experience, the load-serving entities -- the failure in the load-serving entities' incentives to adequately hedge and procure come down to a combination of rules in which the load-serving entity looks across the entire set of what their options are.

And with a price cap in real-time, with certain requirements restricting what they can do in the forward markets, ultimately what we found was a lot of the responsibility for keeping the lights on fell to the ISO to find at the last minute what are the resources that are going to be relied on to be able to supply.

So while we're not concerned about discriminating, certainly don't want to discriminate against who can provide a cap, ultimately, though, it has to be tied to resources that we know we can hold accountable for showing up in day-ahead schedules, that we can give dispatch instructions to, and that are required to perform in --

CHAIRMAN WOOD: So the day-ahead you get from a scheduling portfolio or whomever, you want to know for 100 percent of that schedule you get who to call and that they're really there.

MR. KRISTOV: Yes.

CHAIRMAN WOOD: What is current practice now?

MR. KRISTOV: The current practice is there's no obligation for the load-serving entity to tell us the full amount of what resources they have to meet their requirements. They can simply schedule as much as they have in the day-ahead and then rely on real-time, knowing that there's a price cap in real-time and they'll take a risk, and that load-serving entities can lean on each other, to some extent, if load-serving entity number 1 is short in its procurement, maybe load-serving entity number 2 has extra. But we can't target the blackout if it should occur to the load-serving entity that's short, unless it happens to be a completely continguous geographic area.

To the extent there's any retail access, it becomes impossible to do that. So that there's this externality effect where, if you're short, the risk is you're going to face a high price, but then everybody's going to face a high price; or because there's a price cap in the ISO market, that will hold it down, in which case then we have to struggle to be sure we have enough supply.

So it makes everything somewhat chaotic by not being able to pin down exactly, with a long enough lead time, who the responsible suppliers are, put it on the LSE to identify those suppliers and put it on the suppliers to show up in day-ahead and to perform in real-time.

MR. SHANKER: Mr. Chairman, your question suggested one piece that may not have been clear, that most of us may have been assuming. To the extent we have any asset-related obligations for ICAP market design, what goes with that is if you participate in the market and you are a generator or a load, you're dedicated to the market. Somebody someplace has a hard call on the asset. I mean, we've all been assuming that in this discussion.

So we should make that clear -- and that's the difference between before in California and what's being proposed -- is nobody was dedicated in a sense that if they wished to participate in the market and if they wanted to get compensated to some extent, however the market worked, they also had to fulfill some performance obligations in being there.

MR. O'NEILL: Certainly -- you were talking about demand response. I assume that we would not let demand response into this capacity market unless it could be targeted, and there's no -- you said impossible, but I don't think you really meant that. The technology's available to curtail individual customers if, in fact, we wanted to spend the money and have the ISO do it.

MR. KRISTOV: I was talking about involuntary curtailments. The technology may be possible, but it doesn't exist at this time.

MR. O'NEILL: The choice would be that if you didn't want to be curtailable, you had to be in the capacity option market. It would then be incumbent upon the retail customer or load-serving entity to make sure the technology was available so that demand could respond and you could opt out, in essence, of the capacity.

MR. SHANKER: Nobody can do that right now. Nobody has implemented anything close to be able to -- if you lean on the pool by not participating, I can point to you and get rid of you.

MR. O'NEILL: Did aluminum companies in the Northwest essentially do that?

MR. SHANKER: But those were negotiated contracts for specific arrangements for very large loads.

MR. O'NEILL: Yeah, but they physically shut down.

MR. SHANKER: We're talking about somebody who fails to meet their requirement on a daily or monthly basis. What you're saying is I'm charging a deficiency rate, throw them off the system. And I like that solution, but nobody's shown any capability to do that so far.

MR. O'NEILL: It's not technologically impossible.

MR. SHANKER: There's a price. Everyone who looks at it says it's not economically feasible.

MR. GALATIC: I agree with most of the panelists when they suggest the developers of generation need some long-term pricing, that they need to see a value for capacity, and that's why they're building capacity.

Where I have some difficulty, as I opened up with my opening statement, I think we're stuck in a paradigm of terminology where the industry refuses to recognize that we are paying the value of the capacity in the forward energy prices, that there is -- you can't take the value of capacity out.

Like I said, nonfirm energy, the price of nonfirm energy is near zero. Energy is worthless without the assurance of delivery. What is the assurance of delivery? Capacity, in theory, in price, in practice, essentially without naming the word "capacity" in a firm energy contract, that's what you're paying for.

So there is a signal out there, and it's the firm price of energy reflects the market value of capacity. It's different next year than it is this year because there's generation coming on-line. Out several years, the price is higher, because there's uncertainty, whether new generation is going to be built, whether demand is going to, you know, grow, or how quickly it's going to grow.

So there is a defined market value of capacity right now in the firm energy price. And when we say that capacity separately -- or needs to be separated, there's no way you can separate it.

Like I said, if you make the capacity payment $10 and the price of firm energy is 40, the price of firm energy is not going to drop to 30 because you implemented a capacity payment obligation. The price of firm energy is going to be 40 and you will have a $10 surcharge on top of it.

I also want to throw in there that our risk management policy does not include the option of bankruptcy as a hedge.

MR. WARD: Going back to that question about how do you verify your demand reduction, and if that is a perfectly valid way of satisfying the capacity obligation. In particular, there's that circumstance that develops when a price is mitigated. There is an effort by the market monitor to look at a price, and that price has induced a demand response.

For example, in a state like Maine, it has caused a paper machine to be shut down for a million dollars per hour of lost production. It's very hard to induce people to commit resources on a bid basis for a demand response if they worry that the price might be taken away from them after the fact.

CHAIRMAN WOOD: But to talk about demand response, you know, basically instantaneous interruptibility, of that nature, isn't that really more of an operating reserves issue as opposed to the long term? Can we consider those equally substitutable as far as that social insurance that we want to have, that you can have somebody's interruptible be equal to still in the ground?

MR. GALATIC: I think that's a really good point, because we've been in this market for several years and seeing that everybody focuses on demand response for the operational -- the daily operating reserves requirement, but there's another kind of demand response that generally goes unnoticed. And that is when people, retail customers see volatile prices, prices that are -- or even if they're not volatile, but higher than they expected, higher than they budgeted for, they are more likely to buy basically a long-term contract to get out of the situation where they're exposed to volatility like in New York City right now.

And if they do choose to buy from a retailer, that retailer is then going to turn to the wholesale market and lock in supply for the length of the contract, and that essentially gives stronger price signals to the generation.

New York City is a -- they have a different kind of conundrum where they have political opposition to building anything. As a result, it could be much too volatile in New York City. And so the market has to -- the market operators mitigate the price, and then you have this vicious cycle that's begun where the price is mitigated so it maybe discourages development of new generation because of the severe nature of the mitigation.

And then, because you don't have new supply coming in, you don't have the opportunity for competitive markets to mitigate the price. So you've got to keep the mitigation on. But you still, no matter how much additional price you throw on in New York City, you still don't get new generation built because people simply can't get permits.

That's a local problem that New York City has to try to solve to be able to let new generation come in. Then you can start freeing things up.

Outside of New York City, that's generally not the case, and people do have this opportunity for demand response, just choosing to go long term rather than stay in the spot market.

MS. FERNANDEZ: Since we started late, we're not going to take a break with this panel. So if anyone needs to go to the restroom, you can leave.

MR. OATES: Another demand response, you can curtail them, shut them down, push the button. Just like we're talking about it's tough to build in New York City, the other thing is that these are customer-specific decisions. I may be a customer that I can't afford -- I will not afford any kind of curtailment, and so you could put out a huge price and I won't curtail.

From an operator's perspective, you can only really count on the one that you can push the button or the one that you know is actually going to be there at the time of peak or at the time you need them in a specific portion of your system.

And I think as we design capacity markets going forward, there needs to be a role for those kind of folks to be there who are willing to say okay, I'm willing to spend some money and install some equipment so that when the system needs me to go off the system because I'm a circuit for installed capacity, it can be done. It's not something where I'm going to change my mind or have a specific issue at my facility. I don't want to shut down. I can't afford to shut down that day.

MR. OREN: I wanted to comment about the idea that I -- I perfectly agree that forward contracts include the capacity costs associated with that energy that is going to be delivered under the forward contract.

What we are talking about is the cost of the capacity that is going to sit on the sideline as an insurance against some unplanned event, those generators that most of the time don't produce any energy, but they just sit there for liability purposes just to cover those spikes in demand or some outage. Those are not paid for through forward contracts.

That's why we need options to cover that extra 20 percent that most of the time is unlikely to produce energy, but it's still costing somebody to maintain it.

Now, if you would allow prices to spike, then somebody can sit on the sideline most of the year, and then in three hours, they can charge $5000 a megawatt-hour and make up for the rest of the year that is shut down. But since we are not allowing those kind of price spikes, then we have to provide a cash stream for those generators to get.

So by imposing a call option requirement, then those generators, even though they won't produce energy but they will get the value of the call option, and that will cover them, in addition to any generator that are entering into forward contracts.

MR. SHANKER: Can I follow up on that idea --

MR. MEAD: The notion that what the market won't provide some extra reserve capacity that may produce energy, very little energy, if any at all. Does that suggest that, perhaps, if there is a generation capacity obligation, that it should be for reserves rather than for the full peak load plus reserves?

I guess the notion would be that even if you didn't have the generation capacity obligation, you would still have a fair amount of generators in the ground producing energy and getting revenues enough to meet their costs, and what we might need is a regulatory policy that incented this extra reserve capacity. Perhaps Mr. Hanger's forward reserve contracts might speak to that kind of idea.

Any reactions to that idea?

MR. HANGER: I agree with that.

MR. SHANKER: That's not a good design, and some of us refer to that as capacity on the cheap, because what you've done is expropriated the capacity from all the existing generators and say I'll pay the new guy when he comes in and give him an incentive. And that's great, until he realizes he's in and somebody says gee, you're in, I'll pay you, but I need the next guy so maybe I'll change the rules and not pay you.

It's all fungible to the extent you're going to have the market, and you either pay for it or not. If you don't want to pay for it, take away the market rules that inhibit its valuation.

But I want to finish up on Shmuel's comment about whether or not the value of capacity is in the forward price. In the abstract, it is, but in PJM or any of the markets that have enforced adequacy requirements, it's not -- well, it is, but it's to the extent that it's approaching zero because the market's been suppressed.

If you want a true test of your hypothesis, take away the price cap, take away the reserve requirement in PJM, and then tomorrow see if the forward curve shifts. I guarantee, if you go three or four years out, you're going to see a shift in the forward curves if you change those market rules.

You're a free rider now, and just what we discussed, which is we suppressed the volatility in the markets by putting those rules in place in the first place. Of course firm energy has it in there, because we've expressed the price. Start taking away all those safety nets that you put in there and see what will happen then, and it's not going to be the same forward curve.

MR. GALATIC: A thousand dollars megawatt-hour price cap is not much of a safety net. It's probably much lower than the cost of ICAP. In the last year, when the price in the Midwest was about $2 a megawatt-hour premium to the price of PJM, people in PJM were claiming that ICAP and the safety nets that came with it were the reason why PJM was $2 lower than in the Midwest. And now in the Midwest, the price for summer is $7 a megawatt-hour lower than PJM, and on average, it's about $5 lower than PJM.

Now without any safety nets, the price is much lower outside of PJM. I would expect that because ICAP capacity, so-called capacity in PJM is so disconnected from the actual market for deliverable energy, that if you removed ICAP in PJM, the price curve in the forward market would not move at all. The forward curve is based completely on the promise of deliverability, the deliverability of the energy.

And following up on Dr. Oren's comments about when there's generators that sit on the sideline for reliability because their cost is too high to justify operation in the daily market, but the suppliers need them in case they lose a generator, in case there's an outage, there is an effect on the forward price curve of wholesalers not offering those megawatts up for sale in the wholesale market, and there is some demand elasticity, price elasticity in the forward energy markets.

Maybe not in the same-day market, in the spot market, but in the forward market there is demand elasticity. New generation comes on-line, the price goes down. Somebody holds back some supply so that they have some reserves, it drives the price up.

To the extent that everybody on the wholesale side is practicing prudent business practices withholding some supply from the forward energy markets, that does drive the price up, and they aren't doing that, especially learning from Cynergy's example, when they sold everything they had in 1998, they lost a lot of money.

So people are holding back, and that holding back does cause the prices to go up. Even though there's not contracts where those generators that are on the sidelines are getting directly paid, when you count the increase in price for what people are selling that are actually selling most of their portfolio, a lot of that is -- you could consider it indirect payment for those generators that are on the sideline.

MR. O'NEILL: Roy, I noticed in your list of things to eliminate, you didn't include eliminating market power mitigation.

MR. SHANKER: Of course not, no.

One last comment is that if the forward markets aren't impacted by the existence of a price cap, then I would expect your company to be changing the way it's voting every time we talk about removing price caps in PJM, and you should be hedging, and then we're all done, a lot of this will go away. I'm delighted to hear that people don't think price caps impact forward curves and we ought to get rid of them tomorrow.

MR. GALATIC: My company always votes for the removal of price caps. Would you like me to change that?

MR. SHANKER: We've never seen -- at least I have never seen that position taken. We've always said that ICAP could go away in those markets in exchange for the removal of price caps and administratively set margins, and no one's been willing to support that position.

MR. GALATIC: For the record, we have always voted for the elimination of the price caps.

CHAIRMAN WOOD: You're talking about the $1000 price cap?

MR. GALATIC: Yes.

MR. SHANKER: That's tremendous. If people can hedge, then that's a position that somebody should make sure the Commission rethinks. I personally don't believe that you're going to be willing to do that, and I think it does have a significant impact on the forward curves.

MR. OATES: I guess we've been spending a lot of time talking about market mechanisms to ensure we have capacity located in the right places, and I think we've got to do that, but at the end of the day, we're really talking about this network system that has its infirmity. The load is where it is. The transmission system is what it is, and you can't change that over time.

So if you're to reliably serve all systems and you can't get the power from where it's being produced to where it's needed, you need to have the capacity located in the right spot. So as much as we wanted to make sure a market-based approach incents market participants to build plants, put them in the right place, and for load-serving entities to contract forward and pay for them, at the end of the day, you've got to have the plants in the right spot, because otherwise the lights go out.

CHAIRMAN WOOD: Would you put that obligation on LNC to make sure the power he's contracted for in the forward market is delivered to that actual LSC's territory?

MR. OATES: In New York, you're a capacity resource. Your obligation is to provide or bid your energy into the New York market.

CHAIRMAN WOOD: The New York City market or New York State?

MR. OATES: The New York market.

MS. FERNANDEZ: In New York City isn't there a locational requirement for a lot of your ICAP?

MR. OATES: That's true. I was trying not to talk about New York City too much. That's true. That's another point that I said was important. To the extent you need to have a locational requirement -- and maybe it's during a transition, that's fine, but I think the obligation of the load-serving entity to make sure -- to contract to meet the obligation. We happen to think it should be a minimum of a six- to a one-month obligation that the load-serving entity demonstrate that it's got the capacity locked up for that summer period and the following winter period.

MR. HANGER: Could I speak up for rational price caps because I don't think they're inconsistent with reliability, if it's defined as finding a price cap level in the wholesale market that would allow enough revenue to support a new peaker that maybe runs 20 hours a year or some limited amount of a year. We've done some calculations and maybe 1000 megawatts at PJM doesn't quite get you there, but that's a debatable point, depending upon the assumptions of the cost of gas and some other things. There's certainly a price cap level not much higher than 1000 megawatts that clearly would provide enough revenue to support a new peaker.

So this notion that some are voicing here that you just get rid of price caps and that's the thing you need to do in order to ensure that there's enough financial incentive to bring on-line peakers, our analysis doesn't support that.

MR. KELLY: I'd like to ask a question about who should do what in these kinds of scenarios. I was thinking of four functions. One is to establish such a requirement in the first place, who should do that. Arguably, FERC, but I want to hear comments on that. Second is who should set the level of the requirement, whether it's an 18 percent reserve margin or whatever.

In thinking of your answer, think of, say, the Midwest where you've got a mix of states with retail access and states with historically vertically integrated utilities where the state commissions historically set reserve margin levels. Should the utility be involved? A third function is, who would enforce compliance? Who would make sure that load-serving entities are living up to their responsibility? And the fourth is, who, if anything, should provide a market for selling into and buying from these various instruments, whether demand responses or forward contracts?

MR. O'NEAL: We believe that FERC ought to set, first of all, that obligation to have capacity reserve markets, and they should impose that requirement on the RTOs. At that point, though, the RTOs are free, in our mind, to design that, as fits the particular circumstances of their market, and I suppose that they're a part of the process. The LCs are a part of the process. As you point out, in the Midwest the state commissions and other regulatory bodies should be a part of the process as well.

That certainly all seems reasonable, because you should expect that because the portfolio of assets in each market's going to be different, the capacity requirement should be different in each of the different

RTOs. I think your next question was should the RTO --

MR. KELLY: Enforce its compliance.

MR. O'NEAL: The next two questions are, what is its role? The RTO should be the one that enforces the compliance. In fact, that's currently what happens in PJM where PJM looks to each of the generators in the market and they perform capacity tests to demonstrate that they can provide the capacity that they say they can. I think that's an appropriate role of the RTO and appropriate role both on the generation side as well as the load side to perform -- that both sides can perform their obligation.

Once you do that, then I think it makes sense that the RTO perform some role in terms of creating the market. They run an auction, whatever that auction is, whatever time step we agree on, the RTO should have a role on that, not to suggest that there shouldn't be a bilateral market. There should be a very active bilateral market that people should be able to go to for soft generation or load curtailment contracts.

MR. OREN: If you took the perspective of essentially looking at those markets as some form of insurance for the LSE, I think the natural answer to who should do that, I think it's the state. The LSE essentially operates as a franchise within the state, and the state regulatory body is going to regulate the rate that the consumers are going to pay. So I think any type of requirement that will ensure that the LSE can live up to its obligations should be the jurisdiction of the state.

Also, I think -- in terms of who should provide that, I think private entities, you know, that everybody should shop for it through a bilateral system. I don't see any value of putting that responsibility on the RTO or centralizing that process. If there is an advantage for an auction, then some sort of exchange can emerge that is going to do that, but I don't see any reason to include that as a part of the functions of the RTO.

MR. OATES: I had in my opening remarks my three elements, and I guess my first one was that an independent entity just sort of establish that this is important. So I think FERC can have a role there saying it is important to have a capacity obligation. But then you could have the regional reliability council, whomever you want to call it, that really sets what's the percentage, what's the reserve margin and then leave it up to the RTO to establish, okay, how much does that then mean as far as megawatts of capacity, that each individual LSE has to procure.

I think it's important to have this market-clearing mechanism. There are changes in who is serving which particular customers. Customers can change load-serving entities within a capability period. You have a way to sort of know what the market is placing a value on capacity. So if you need to have a switch of capacity from one LSE to another, at least you have a way for that to take place.

MR. KELLY: New York is unusual because it's got a reliability council. Normally the regional reliability councils don't set long-term capacity reserve requirements. Do you agree with that?

MR. OATES: That it is my understanding. I was just pointing out this is one way it's done now. It's important that that's an independent entity that does the analysis and says okay, here's my percentage. If we're going to have a capacity market, the reserve margin is X percent and leave it up to the RTO to figure out how much each individual load-serving entity needs in each location where they're serving load.

MR. WARD: I see a minimal role for the states, at least in the corner of the country of which I'm familiar. I think in the first instance it's up to this Commission to establish the general design of a capacity responsibility-type mechanism, but from there, I agree with Mirant, in the first instance, looking at compliance issues. So I think the horse has already left the barn with respect to state regulatory oversight on this type of issue, at least in New England.

MR. KELLY: We certainly saw instances in the west where states that had reserve margin requirements found that that extra capacity either needed to be sold to avoid a withholding charge or had to be sold simply out of good citizenship and diluted the reserves from the states that had the requirement, making a single state reserve requirement difficult and perhaps suggesting that it's early federal, regional, RTO, or somehow multistate agreements.

MR. WARD: I share a concern about what happens to a regional grid when state prerogatives drive policies rather than regional prerogatives.

MR. HANGER: I would like to second that. The responsibility initially ought to be FERC driven and then delegated to the RTOs, and I think that's even more important as RTOs expand.

MR. SHANKER: Again, I will go along with the FERC or some independent party setting the general reliability standard 1 and 10. The enforcement mechanism should be in the RTO. It is feasible for it to be different, but to be different, it has to be enforceable. So you can't draft somebody involuntarily.

So if you want to have this separate mechanism, you have to have standards to differentiate. It's possibly feasible for control areas. We know it's not feasible within sectors within a single market right now. It's just not possible. There is a governance issue here, though, and that has to do with the day-to-day process has to be across the whole stakeholder process. PJM had some significant flaws in the design of its capacity market.

Inevitably, it was unable during the governance structure that was in place in PJM to solve it. Only load-serving entities participated in that voting process, and it was stalemated. Actually, I guess the only things I have seen to fix this were 206 filings at the initiative of the RTO and not through the stakeholder process.

So you need to consider the governance aspect of this. This is a controversial market, and if you set up something that has potentially bias one way or the other, generator or load, the governance has to match the ability to respond to that.

MR. KRISTOV: Speaking from what we're doing in California now looking at it, there's, I think, a role for a number of parties. The ISO right now is playing a catalyst kind of role because we're talking about going from a situation where there is no obligation to actually starting from scratch and defining what that obligation ought to look like.

And a lot of that definition comes right back from our experience over the last couple of years and the day-ahead and real-time deliverability and performance issues that we want this capacity obligation to serve. So that's where our starting point is in thinking about it.

Now, it seems to me that given California's situation, plus our reliance on imports, how we're going to treat imports, who wants to supply capacity, et cetera, not every jurisdiction is going to have the same context. So having the Commission set an obligation on ISOs and RTOs to ensure adequacy, then allowing some flexibility in how they go about meeting that. And in our situation, it's going to have to be dealing -- working cooperatively with other state agencies in a number of ways.

For example, the Public Utilities Commission certainly regulates the procurement practices of the utilities as load-serving entities. They would need to meet this obligation and be assured that they can do cost recovery, et cetera, and that their procurement practices are prudent.

At the same time, to the extent that there's direct access and nonutility retailers, while they do operate under a state franchise, the ability of the Public Utilities Commission to enforce an obligation on them is, at least in my mind, unclear, so that the enforcement coming from the ISO level saying that if you're an ISO participant or you're scheduling load through an ISO scheduling coordinator, that's how the obligation is going to be defined.

There's also, I think, a forecasting question of what the obligation should be and from the ISO's point of view, we don't track which load-serving entities own which retail customers at any given point in time. We can look historically at how scheduling coordinators' loads have changed, but we don't -- that's not a good basis for prediction where there's opportunity to switch customers.

So we have a state energy commission that has been doing forecasting for the last three decades, and that forecasts on the basis of service territories, plus the distribution companies in their role as operators of the distribution system track where every customer is, which load-serving entity each customer belongs to and so on.

So there might be a role for the state to take up outside of the ISO to do this defining what the -- or actually assessing what the quantitative number should be for that obligation. And right now we're exploring different ways to develop that collaborative approach.

CHAIRMAN WOOD: How could what y'all propose account for the fact that the hydro, while the installed capacity was what it was, just wasn't there? I guess to go back to -- I think your phrase, Alex, was deliverable energy. Is there something in the new market design proposals for the Cal ISO that would make that, I guess, problem from last year not be a problem anymore?

MR. KRISTOV: I think to some extent it's a forecasting problem. We try to forecast what hydro resources will be available, but when it comes down to what a load-serving entity's obligation is going to be, then the problem is we have not got the algorithmic solution to it. But the problem we're trying to grapple with is how do you count resources toward meeting that obligation.

When you've got a total number of megawatts difference than the monthly obligation is, different types of resources and contracts contribute to that. If we've got a resource that says well, I can give you this capacity 24 by 7, but I can only run 14 hours out of the month or I've only got a certain number of megawatts, well, somehow that gets discounted in an appropriate way to count towards meeting the monthly obligation.

Then when we do our daily day-ahead run of energy and congestion market and whatever unit commitment and so on, then we take into account those resources constraints in the day ahead algorithm. Somehow all that translation has to work. That's the concept anyway that we're pursuing.

MR. KELLY: I was going to ask this later, but now is a good time since we've introduced the hydro. If you have an area that's substantially dependent on hydro -- the west, I think, is about 30 percent hydro -- and you can count on that hydro to be there 29 out of 30 years, what do you do about planning for the 30th year when it by and large doesn't show up, that 1-in-30-year drought?

A simpleminded solution would be to say you need to build enough extra thermal generation to be there for the 30th year, and then you've got a reserve requirement. But that seems expensive, and it doesn't allow utilities, particularly those that are much more than 30 percent hydro, to count their resources toward their reserves.

Have you wrestled with that issue?

MR. KRISTOV: I'm not an expert on this. At least one initial thought I would have is the larger the geographic scope of the region, the less of a problem that is. To the extent we resolve seam issues and the availability of supplies in one region to meet capacity obligations in another part of the area --

MR. KELLY: I picked the west, because I think it's 30 percent hydro.

MR. GALATIC: The forward energy prices reflect the risk of that supply not being there or potentially not being there, and when it's not around, the price goes up and sends signals that maybe somebody should build some kind of generating capacity.

But I'd like to also answer the question that was going around in terms of who should be administrator of any obligation. Frankly, like the California ISO's proposal. If there's going to be a supply obligation, make it real and make it tied to deliverable energy, but I would hate to have to go negotiate the details of implementation 48 times, you know, over time, because when that -- when the ISO first proposed its plan, I met with one of the people that were responsible there for the implementation, Mr. Byron Woods, for two hours going over some of the implementation details and concerns of how do you handle potential unintended consequences. And it would be very difficult, I think, to manage that process on a state-by-state basis. Then you might have seams issues from state to state.

MR. OREN: With regard to the hydro, you know, this is a problem that actually I was dealing with in South America where they have exactly that problem, in Colombia where they have four years of wet water and then the question who pays the thermals who are paying on the sideline during those four years so they will be available when there's a drought. I think again by thinking about it from a point of view of call options, if the hydro is off, it's a question of choosing the time step.

If the hydro is providing the call option on the capacity, then in order to cover their risk, they would be in a position to have to buy a call option from the thermal that is going to protect them in the case that there is a drought and they are liable for delivering the energy at a strike price that they committed themselves to. So it's all a question of risk management, and if you look at the risk management and a portfolio of different financial backups to the energy price, then it all kind of takes care of itself.

MR. SHANKER: Just remember one day in 10 means one day in 10. That means that two or three hours a year we're going to be short. Mechanically, these standards are predicated not on there never being an outage. The question is, what do you do? We can manage it financially. We can point fingers at people who may have taken different risk positions in reserves they've chosen and cut them off the system, but 1 day in 2 means 2.4 hours a year there's going to be demand in excess of supply.

You throw in some transmission outages and things like that, and you have physical shortage situations, and that's the nature of the system, and we've all sort of collectively decided that it's not worth the incremental investment to reduce that when we have administered reliability.

MR. O'NEILL: Has anybody empirically validated the 1 day in 10?

MR. SHANKER: After the fact?

MR. O'NEILL: We've been operating under a 1 day in 10 standard for about 30 years. Does that reflect realization?

MR. SHANKER: The history of 1 day in 10, probably somebody picked the numbers out of the air. In the late '70s, there were studies that, I think, DOE funded that were called the over/under studies and they looked at the trade-off between the cost of incremental generation and the cost of unserved debt. It concluded that the crossover point for cost minimization was about 1 day in 10. After the fact, did somebody say ah, it turned out to be one day in 10? I don't know that.

MR. O'NEILL: This still remains sort of a theoretical construct?

MR. SHANKER: It's a design standard because you're going to see people dropping voltages. You're going to see a lot of other emergency actions. You're going to see people go to short-term ratings on some of the transmission lines. You're going to see a whole bunch of other stuff happen before you drop the load. So you're never going to get the same situation in real operation as you are in a planning standard.

MR. O'NEILL: Can I ask another question? Roy and Alex have been going back and forth about the forward markets and the forward price curve. If we were to start relying on that or paying attention to that, there seems to have been a debate that has been raised recently that those curves are not terribly robust and not as competitive as everyone would like them to be.

Since you guys have been operating in that market, do you feel that these are markets that can be relied on?

MR. GALATIC: The forward energy markets are -- their liquidity varies from region to region. There are several hubs where the liquidity is very high, especially for, say, the next 20 months' trip, and liquidity starts to drop off as you go forward into the future where, you know, five years from now there may not be a lot of buyers and sellers and for the year 2007 right now.

It's like every other market. The liquidity is greater as you get closer to the spot market, but the forward markets in general, we think, are very competitive around the country that, the price generally reflects a competitive price for forward energy. And relative to the -- what we think are poorly designed ICAP markets, you've got competition in the energy markets, but you don't necessarily have competition in --

MR. O'NEILL: How do you come to that conclusion, that you feel the market is competitive? What metrics do you use to measure the competitiveness of that market?

MR. GALATIC: We are in the markets every day updating our forward curves based on what people are willing to sell us power at, and we have a significant number of counterparties that we buy from, and we always can get an offer for -- you know, a price offer for everywhere where we sell electricity at retail. Right now we're in New York, New England, Pennsylvania, Ohio, California, and Texas.

So there is -- from our perspective looking at this over the last four years, we've seen the prices in 1998 where they were about maybe $5 a megawatt-hour lower on average than they are right now. We've seen them go to the forward market in the summer and PJM and Cinergy both up over $200 a megawatt-hour in the forward market for the summer months. And since then, it's been dropping off as new generation is coming on line. It really looks like the energy markets are reacting to supply and demand.

MR. O'NEILL: It's interesting, because you said five years out the market is not very liquid. I would think that that should be where the market was extremely liquid because that's the lead time for building a new generator. So anybody could be in that market.

MR. GALATIC: To the extent that we have customers that want to lock in a price for five years, we're going out and we're creating some liquidity from the buying side, and there aren't quite as many sellers out five years as there are for next month, but there is still some liquidity. And to the extent that that's what generators want, that's what we want as well.

MR. SHANKER: To answer your question about the depth of liquidity in the context of hedging full markets on three or four-year terms, I don't know for a central market if it's there or not. If it's empirical, I wouldn't think so. Certainly they are competitive in terms of anything you would need to be concerned about. It's a question of whether the depth is there.

The point of my concern before was -- is that you cannot assume that the existing capital stock as a sunk resource is not reflected in those price -- in those prices and that the regulatory structure that made those resources sunk is not reflected in those forward prices and that the presumption that you can go around and change the basic rules for the formation of capital and the obligations for capital and assume that they're not going to show up in the forward prices is just wrong.

MS. FERNANDEZ: Why don't we let Mr. O'Neal and Mr. Oates speak.

MR. O'NEAL: Building on Roy's point, the markets are liquid, and, you know, we look at the large number of counterparties and the large number of transactions that go on. As you go farther out, they are less liquid, and it's mainly a function of the number of counterparties that are willing to transact that far out.

I think as you -- I guess the way we view it, there are more sellers than there are buyers in these forward markets. You have a lot of people still locked up behind standard service requirements or uncertainties about the competitive market. Whereas on the wholesale generation market, you've unlocked that. That's out there.

So you have a large number of sellers out there participating in that market, not nearly as many buyers who have some certainty about what their future holds. So it gets a lot less liquid as you get further out. Having said that, I think as Roy pointed out, it is competitive.

The markets move every day reflecting the fundamental of supply and demand.

MR. OATES: I guess the only point I would add, I guess I agree with Roy on this issue of do forward energy market prices reflect provided capacity. I don't think they do. I think the other dynamic and something John touched on is that retail deals, standard offers, those sort of stuff do incent people to want to go out five years.

I don't know five years from now whether I'm going to have a retail obligations, and I have some existing long-term resources that I'm using to go forward. Five years from now, I could have zero. Forward energy markets may not solve the problem. A capacity market does, because if I don't -- if I'm not buying the capacity, somebody else that is serving load that I am serving is going to have to buy the capacity.

MR. MEAD: How do we make the long-term obligation really a long-term obligation and not just a duplication of the real-time market? If the concern is that energy markets by themselves won't elicit enough capacity and it takes a couple years at least to build new capacity, does that mean that any capacity obligations needs to be established a couple years in advance? What good does an obligation that must be met a month or six months before delivery do to serve that need?

MR. O'NEAL: I think that empirical evidence shows that the lead time varies from region to region around the country. We've seen in some places they've been able to bring peak capacity on within 12 months. Other regions, it's practically impossible. So from the perspective of how long should the obligation be, if it is impossible, then -- like in New York City, for example, it's not impossible, but it's darn near impossible. You have to consider how much -- what do you want the nature of the obligation to be? Do you want it to be an extra payment for something that you'll never get anyway?

Conversely, in the Midwest, if you have the opportunity for someone to come in and alleviate the market conditions by building a peaker and very quickly and they could do that within a year, then should the obligation be any longer than that?

MR. KELLY: I have a question. I need somebody to help walk me through something. What I've heard is that it's not terribly useful to have a capacity -- something like an ICAP credit obligation that lasts a week, a month, or even a season. Roy Shanker said it needs to be long term, which I took to mean a few years. So I have to go out and sign some sort of long-term contract.

MR. SHANKER: Somebody has to obligate long term.

MR. KELLY: Suppose now I do that. Suppose I sign a bunch of four-year contracts that satisfy the obligation and the market happens to be a little high right now for long-term contracts, and next month, Dick here, when the market goes down, he goes out and signs lower costs long-term contracts, but I'm a supplier in a retail access state. Dick offers them a cheaper price since he signed cheaper long-term contracts.

First, how is he able to sign up those long-term contracts without customers, or if he does sign them up and offers a cheaper price and I lose them, what happens to the contracts I sold? Is there some market where I can sell into and Dick will buy from and it gets transferred? Mechanically, how does all that work when you've got longer-term obligations rather than weekly or monthly obligations?

MR. SHANKER: The first thing is having long-term obligations doesn't mean there's no liquidity in the short run in changing or exchanging them. There are different mechanisms you could do. You could have a three-year obligation that it could be cleared in monthly increments and you could establish transfer prices or clearing prices monthly, and those could be the prices at which you exchange on.

The other options are you could have central procurement, which establishes -- the ISO, the RTO doesn't enter the market. The ISO buys ICAP in the same sense it buys ancillary services. It fulfills the obligation, and the charge just goes with the load, whoever has them. There are mechanisms to integrate with retail access for long-term obligations that aren't that difficult.

I mean, there's a couple ways to do it, and those are two that I mentioned, established clearing prices and have a central cost that then gets divvied up as you go forward. It doesn't matter where you go, you pay your share. There's lots of ways to do it.

MR. OREN: One way to think about it is the same way we think about, you know, 30-year Treasury bonds. They're issued for 30 days, but they're traded every day and priced to market. So the fact the obligation is long term does not mean it cannot be traded and the value adjusted to changing issues.

MR. KELLY: The key is that it needs to be long term. Do all of the panelists agree that the short-term, weekly, monthly, obligations of many existing ICAP programs are inappropriate and that longer-term obligations are necessary, if you support the concept at all, I should say?

MR. GALATIC: I would like to just mention that if there is a forward supply obligation, if it is longer than the term of my company's retail contracts, then essentially we're being forced to take a long position, the price of which could change, and we could -- if it goes down and our customers don't extend the contract, don't renew the contract, then, you know, we have the potential for a stranded cost situation because we were obligated to buy that obligation.

It sounds like a double, but if we're mandated to buy that -- some kind of capacity obligation longer than we have -- I shouldn't say -- for a longer term than we have retail contracts, then essentially we're being forced to take a commodity position.

MR. SHANKER: People buy long-term commodity positions all the time for longer than their current needs. People build power plants for 30 years with maybe only four or five years of sales hedge. That's called business risk. This is a competitive environment.

MR. GALATIC: But it's not forced business risk.

MR. SHANKER: The issue is to get the obligation into horizon where you can do two things, one, where you can see rational marginal costs, not zero, because we're long and a deficiency rate because we're short and it changes daily based on short-term behavior.

The second thing is to make the time horizon for the obligation consistent with the underlying planning assumptions. If you go down to the mechanics of the LOOP studies, one of the things they all do is they consume in that planning the ability to shuffle around generator outages. So they sit there and plan the existing base, maybe out to 18 months, and they shuffle them around in a fashion that tries to even out the outages.

When someone says 15 or 18 percent is adequate for 1 day in 10, they've said it based upon assumptions that you do certain things for those generators. I can move the outages and structure the outages any way I want. So if you want to consume reliability consistent with the planning criteria, the minimum time frame you need to have is a planning time step that matches what you did in the LOOP studies.

MR. MEAD: In a minute or two we will be taking a couple of questions from people in the audience. A couple of our staffers have microphones. So if you're interested, get their attention. That will happen in a minute or two.

MR. HANGER: Can I say a couple things? I think there's a couple other things that need to be kept in mind. Certainly within PJM I think some generation owners are being reluctant to support the longer-term commitments. When those longer-term commitments really mean they have to deliver energy on the call of the ISO. So the opposition to longer-term commitments, I think, is predicated on a couple things.

One is in the past some of these folks have really had their cake and eat it, too. They can receive capacity credits and sell energy elsewhere and de-list their capacity on very short notice. So one thing, if we're going to have longer-term requirements, let's make sure that it's longer-term requirements to create real delivered energy. I disagree with this imagery of what's important is iron in the ground.

What's important is delivered energy, and the rules -- you can get a lot of iron in the ground built, but if you don't have the rules right, you're not necessarily going to have delivered energy within the control area. So I'm a little bit agnostic whether the forward price curve right now as developed is sending enough price signals to create enough generation over a longer period of time, but I caution against sort of rubber stamping particularly the PJM models.

There's a lot of folks who think PJM walks on water. I think they walk on a lot of water, but not the entire ocean. And this is one area -- this is one area where they've been drowning. I would prefer us to look at things like operating reserve market, because I think that's close to the concept of delivered energy, what we're really after, and having a forward market that is over a long period of time, two-year period for operating reserve market and perhaps imposing that as a requirement on the RTO seems to me to be getting to the real issue, which is making sure we get delivered energy to keep the lights on.

CHAIRMAN WOOD: I want to ask something I guess I call the trigger. There are a number of markets that don't have ICAP, never did, that seem to be in a pretty big overbuilt situation. I think Alex, you or somebody pointed out --

MR. GALATIC: I mentioned Texas.

CHAIRMAN WOOD: Yeah, I've been there. What would the reaction of the panel be to a regulation by this Commission that if you pierce a floor looking forward, say three years out, your projected reserve requirement for your RTO region drops below 15, 18, whatever the number is, 12? Then a mechanism kicks in along the lines of what we're talking about here and all the bells and whistles that we have weighed out from the panel. Would that be unnecessary? Should you go ahead and put one in now? What would be the implications of doing something like that?

MR. GALATIC: I know the Texas Commission is --

CHAIRMAN WOOD: Yeah, I'm reading everybody's pleading in that docket. That's where the idea came from.

MR. GALATIC: If you're going to have some kind of extra incentive, call it a capacity payment, call it a subsidy, what have you, if you're going to do that and you're going to kick it in, when the reserve margin drops below a certain key number, trigger number, then you might have the unintended consequences of developers not building in hopes of capturing that subsidy. So you almost guarantee that the reserve margins will drop to that level. I think we have to be careful about that.

MR. SHANKER: You're just creating a gaming situation. You either have it or you don't. If you believe that -- the predicate for why you wanted to do this was you felt if it got too low, prices might be too volatile or physical reliability might not be adequate to meet your social objectives.

If that's what you believe, say it now, put the rules in place, and let everybody play by them. It's just that simple. If 12 percent is where you're going to get upset, say it now, and that's what will happen, and it may be if you start long, the value of capacity might be zero for three or four years. At least everybody knows the rules going in.

CHAIRMAN WOOD: What if you don't know that what we've got now in ERCOT is better actually than what we've got in PJM?

MR. SHANKER: If it goes below 12, are you going to be happy with the price consequences of doing nothing? If the answer is no, then fix it now; and if the answer is you're happy to see the market continue to work on a voluntary basis, then keep your hands off. It's the uncertainty.

The moment you suggest that you might provide another hedge -- like Shmuel said, bankruptcy, the moment I know I can go to you and get another hedge by saying uh-oh, we got in a bad situation, you've created another distortion in the market that's not fair.

MR. OREN: This obviously comes up at ERCOT. I think the point is that if indeed you have extra capacity, then any kind of call options are going to be very cheap. So why not do it? That's going to be reflected. It's like buying flood insurance when you're living on the hill. So it's going to be cheap.

But the point is if indeed you think that we have -- you know, when you have so much capacity, then somebody's not running and losing money. So that capacity may disappear faster than you think. They're not going to get some sort of mechanism to maintain a cash stream. So I think that, you know, we've seen that in California how quickly the excess capacity eroded for various reasons. So I agree with Roy. You have to establish and have the mechanism in place, and if indeed there is excess capacity, that's going to be reflected in prices.

MR. OATES: There are a lot of variables that go into that, what's your peak demand going to be. A lot of projects in the development stage, are they going to show up and what year. So the assumptions you make sort of drive the reserve margin that you see.

CHAIRMAN WOOD: Don't you have to do that anyway to let the LSE get the appropriate amount of --

MR. OATES: Use the New York example. You set the overall reserve margin 18 percent for an annual basis and then the ISO calculates how much capacity each entity needs to buy. As long as you know there's going to be this reserve margin consistently going forward, load-serving entities are going to have to make the decision if I'm in the business, I have to meet my capacity needs going forward.

If I think I'm going to get out of the business or serve this market, I'm going to contract for the period of time I'm going to serve the market and I'm going to leave, and somebody else is going to be there, probably the utility, probably somebody like me. The utility's there. It's going to have to pick up the capacity. Somebody's going to have to pick it up.

MR. MEAD: We have time for a couple of questions from the audience.

MR. CASLOW: Tom Caslow from Calpine. I want to follow up with a question about whether it make a difference who determines the level of the requirement and who administers enforcement. Implicit in that question seemed to be asking the panelists whether there was a concern about, if you had one entity versus another do that, would the quantity and the effectiveness of the enforcement be a question, would there be any concerns?

And the question to the panel was, with that as a background, would the market be self-correcting under any structure of who administers and who determines requirements if the obligations associated with capacity that would be placed on generators would not be placed on them unless they were purchased as capacity?

If the question was too long and you need a restatement, please ask a clarifying question. I will direct it to you first, Roy.

MR. SHANKER: I'm not sure I understand what you're getting at. The general reliability standard, 1 day in 10, I'm pretty happy with anybody setting that. I haven't seen a lot of fight about gross reliability standards. Translating that to a specific standard, again, you know, 18 percent or whatever, there's been fighting about, but I think that's reasonably a doable problem. The allocation to load zones gets a little more controversial as you get closer to individual, it does. But once you get down to that level, I think it's an RTO function.

The enforcement mechanism has got to have penalties that bite. Somehow or another it's got to be really painful to not participate. This is a tax, or mandatory insurance or a tax, which are very close in my mind. You've got to have a way of enforcement.

I don't know if that answers --

MR. CASLOW: Perhaps let me re-ask the question, because the last part of your question identifies the ambiguity. The real question was, one person's penalty might be deemed by someone else to be insufficient for it to be effective enforcement. Can that debate be put off to the side if, in the market design, there is assurance that no one will be asked to take on the supply obligations associated with capacity unless that capacity is purchased from that resource? The nature of the question is --

MR. SHANKER: That says you're going to be able to throw somebody off the system if they don't participate.

The answer is you don't need an enforcement mechanism by price if I can point to the guy who doesn't participate and throw him off the system.

MR. MEAD: I think we need to move on. Is there somebody else in the audience? I see a microphone over here. Please state your name and organization, and if you could -- since we're short of time, if you could direct your question to a particular panelist, that would be helpful.

MR. BLOOM: I'm Robert Bloom. I'm an independent economist and investment banker. My comment concerns a remark by the Staff, and so if I have to direct it to a particular member of the panel, I suppose I would direct it to the Staff.

My comment is fundamental. They have betrayed a deep -- a skepticism about forward markets, about the competitiveness of forward markets, about the robustness of forward markets. Now, there are two ways you can deal with that or two responses to that.

One is you can dismiss them and say relegate them to the realm of they're not physically real, they're financial, they're for speculation and so on. We go off in one direction and then we try to develop alternatives to them.

Or we can say yes, they're underdeveloped, let's go and try to reinforce, let's try to develop those markets on the basis that maybe they are the basis for the entire market and be very careful about what we establish as alternatives because they could perhaps even jeopardize those markets. For example, the market itself, the provision of a market or an exchange is itself a competitive business, and there are operators of bilateral market platforms, and there was a clear case in California where a market operator, APX, tried to compete with an established exchange.

So we may want to look with some caution about empowering -- for example, taking the conclusion that forward markets have these maybe inherent difficulties and that we have to reinforce short-term prices, short-term spot markets, as an alternative, when in so doing, in institutionalizing those, in standardizing those, we're actually empowering them from discouraging people to use those long-term markets, which we think they should.

I want to cite two examples. One was just a year ago when everything blew apart in California --

MR. MEAD: If I could interrupt you for a second. We're a little short on time. Do you have a specific question?

MR. BLOOM: Yeah. My question is there are two alternative ways to approach it. My fear is the Commission is going one way. My question is, wouldn't it be able to go the other way?

My example was just a year ago when things blew apart in California and all the participants were coming to FERC. FERC recognized we don't have bilateral markets in California. Back when the exchange was set up, Professor Wilson at Stanford, you know, was very worried that there were no forward markets in California, and he so believed that forward pricing was so fundamental and that that had just been neglected. Here, when it fell apart, FERC was being begged and there were hearings before an administrative law judge to try to say well, how do we set up bilateral markets, how do we price and so on. So that matter was faced. Of course, that was very long.

But I bring FERC back to those days where the impression might be if those markets have this fundamental weakness, why don't we concentrate on setting up conditions that are going to make those forward bilateral markets flourish, rather than write them off and say we've got to go to these spot markets and these institutionalized, centralized unit dispatch markets, and so on.

That's my remark and my question to the Staff.

MS. FERNANDEZ: I will take that under consideration. Can we have the next question?

MS. KILBORNE: Kind of along those same lines, my name is Becky Kilborne with Deloitte & Touche, but I speak on behalf of my experience at the California Power Exchange during the meltdown last year. My experience was a little different from Lorenzo's because I observed it as a market operator.

What we saw and what is not generally known is that the IOUs did have a lot of capability to hedge forward in the power exchanges, standardized forward markets. But what happened was as we saw the caps come down, as we saw caps instituted at levels that caused people to quit contracting forward because they had caps in the real-time market and the day-ahead market, so that caused the volumes that the ISO had to procure out of market to increase and that created a significant amount of the problem.

As soon as all those were out of the market, that destroyed the forward markets, because there was no incentive to contract forward. So I think a lot of what we're talking about is the regulatory controls that are put in place for the forward markets. PI agree with Alex. That's how you're going to accomplish, and also with Dr. Oren, that that's how you're going to accomplish the capacity markets that you need, to allow the forward markets to work.

I also think when you described the incentive for an energy service provider that has an obligation to serve but is under contract, they have every incentive to use the forward markets to hedge their forward risk. I think the real issue we're facing here is the state regulator and how -- FERC is trying to institute some way to get around the state regulators positioned to second-guess what the utilities do and somehow constrain their activities so that they can't -- the forward markets won't flourish.

So I guess my question to the panelists in general is, isn't the root cause here really this issue of the state regulators and how they regulate the load-serving entities and why don't we just be straight with that and figure out the answer to the question?

CHAIRMAN WOOD: Let me just ask you back. We're putting a mechanism on any load-serving entity, whether it's state regulated, or in an unbundled state, not regulated, but putting an obligation on everybody to, I don't know, buy 10 percent more than your daily peak or show us contracts for 10 percent more than your daily peak with a mix of load curtailment, new generation firm, iron on the ground or however we want to define that, or what was your third one, John?

MR. O'NEAL: Curtailment contracts.

MR. GALATIC: Demand response.

CHAIRMAN WOOD: Demand response. That 110 percent of your last summer's peak -- is that sort of stuff historic to the forward market, too?

MS. KILBORNE: I think that in the purest sense of theory, probably, because it becomes an administrative requirement, and you've heard some of the issues that ham around that, and then how do you track it. I agree that it's probably better if it's a requirement -- that it isn't a steel in the ground sort of a requirement but it's more of a financial contract.

Given the situation with states, as Dr. Oren suggests, maybe you do want to do something like that given where we are today, but it's maybe something you would want to phase out over time. That's my personal opinion.

MR. OREN: May I add something? I think that it's helpful to have kind of a unifying perspective, like when you impose a price cap, then de facto any capacity obligation that has to -- with delivery requirement becomes an option with that price cap, the strike price. If you wanted to lower it, then you can think of it as another form of mandatory contracts.

Now, whether we actually need to mandate that or we can trust the market, you know, it's kind of the Russian saying that trust is good, but control is better. So I think that that's something that you have to decide, but I think in the short run, probably we need some form of control.

MR. MEAD: I think we have time for maybe one more question.

MR. JONES: Brad Jones. I wanted to ask a question, but I also wanted to make a comment with regard to --

MR. MEAD: Could I ask you just to pose -- since we're running short on time.

CHAIRMAN WOOD: I want to hear both.

MR. JONES: Thank you. Basically the comment was in regards to whether or not you could set forward some reserve requirement that you would look at as a target, and when that target is not achieved some time in the future, that he would implement a plan at that point.

Now, what I'd like to say is in ERCOT that has worked very well. Back in 1998, the COO Sam Jones went on a "y'all come" tour. He essentially went out and said we have gone under these reserve requirements, we believe we have a good market, and we expect generation to come to that market, and it happened. Generation came. I think that's an effective tool.

The question I wanted to ask, though, is really to Dr. Oren and to Alex about whether or not you should require forward loads several years in advance to contract. I'd like to hear Dr. Oren's response to that, whether you should require loads to contract five years in advance, three years in advance when they may only have contracts with their customers for one year? How do you manage that?

MR. OREN: Well, you know, I mean, there was some discussion here. Trying to bridge the gap between long-term obligation and short-term entitlements and so on, this is something that we see all the time. Savings and loans give 30-year mortgages and take on savings that you can withdraw on a day's notice or on a month's notice.

So I don't see any problem with this kind of an approach of asking the load-serving entity to engage into long-term contracts based on, you know, their current set of customers. Supposedly there will be a market for those contracts. So if they lose their customer, they can unload them. For those contracts to be meaningful and to have, as Roy said, meaningful prices, they have to be longer, contracts that are kind of within the scope of the planning horizon.

CHAIRMAN WOOD: How does that work in a recall environment where you have a significant return, particularly for a smaller provider?

MR. GALATIC: If we have a requirement to buy three years of supply or longer, then our minimum retail contract will be three years, because our risk management policy does not allow us to speculate on commodities.

CHAIRMAN WOOD: So is there any middle ground between, you know, do it and don't do it at all that works particularly in an open state?

MR. GALATIC: The California ISO's proposal. Show me that you have supply lined up or rights to supply lined up for the next month. If you want me to show you the supply that I have lined up for my customers in California for this summer, I can show you right now. We don't have to wait until July to show you what I have lined up for August. It's imprudent business practice for me not to have supply lined up for August right now.

CHAIRMAN WOOD: How does that give the signal to the merits of the world?

MR. GALATIC: We have contracts with customers who signed up for five years.

CHAIRMAN WOOD: But you don't have to show those to the ISO.

MR. GALATIC: We've sent the signal to the generators because we're expressing an interest in buying power out five years.

MR. SHANKER: The problem is the enforcement -- the link between this behavior and the enforcement. It's the guy who doesn't do this and sees the monthly price and then in the short run the monthly price is zero or it's at the deficiency. He's either fat and happy and refuses the hedge or comes here and complains when the market goes short and there's a deficiency charge.

If you want to get everybody to see reasonable marginal costs in the long-term structure, you're going to have to create a visible mechanism for that. There can be two responses to Alex's concern. One is other people may be willing to compete with a different risk profile, and that will get settled out.

The other is whether you evaluate a central procurement where that risk is not his, it's the market's risk, that the load carries it and they may just shuffle it around over time, and the market has a rolling three-year, four-year auctions that they buy for. He has to pick it up at a price -- the standard clearing price for the loads he has, but when he loses the load, he loses the liability. That would insulate him totally. So there are mechanisms to do it. You can put it sort of in an overhead structure where all load carries it and he's off the hook.

MR. GALATIC: It's like a tax that follows the customer?

MR. SHANKER: It's like a tax that follows the customer.

MR. OATES: I think we have to be careful about establishing long-term requirements, because there's consequences there, too, but I'd be reluctant to establish a one-month requirement or so.

MR. O'NEILL: This requirement would be different for western New York and New York City?

MR. SHANKER: The duration would be the same. The pricing -- we can have lots of mechanisms that reflect locational differences in prices, sure.

MR. MEAD: Thank you all for your time.

MS. FERNANDEZ: Since we've gone a little bit late, how about we start up the next session at 12:45 so you get your full hour for lunch.

(Whereupon, at 12:45 p.m., the technical conference was recessed, to be reconvened at 1:45 p.m. this same day.)

AFTERNOON SESSION (1:50 p.m.)

MR. HEGERLE: My name is Mark Hegerle with the Office of Markets, Tariffs and Rates. I see we have David Mead and Alice Fernandez here. I'm sure we'll have other staffers join us here in a few minutes.

We're going to talk about what the standard markets on tariff ought to look like. A lot has changed in six years since we wrote the pro forma tariff in Order 888. I'm sure all of you sitting in front of me have an excellent idea of what a new tariff should look like, whether we should throw away what we've got and start over.

MR. GILDEA: Good afternoon, and thank you for allowing me to speak here today. I'm a manager for Duke Energy North America in the trading subsidiary, with lead responsibility in market policy issues of the broader Midwest, and I directly participate in the stakeholder process within the MISO, and not long ago, the forum sponsored by the Alliance sponsoring southeast RTOs.

As a regulatory manager, my primary clients within my company are my energy traders, my transmission desks, my asset operators, my origination team, my merchant project development company, and along with my corporate management. My experience to date has convinced me that an efficient and equitable transmission tariff is the key platform in which these individual competitive business entrants will thrive and meet the needs of this Commission's agenda.

The markets I focus on are exclusively still in the contract path world. And working on the front lines in the merchant community, I experience daily challenges afforded by business interests due to a tariff that was extensively set up for the world when generation resources were really exclusively set up to serve the local load on a long-term basis.

My comments today focus on outside incremental changes needed to today's OATT in order to sustain wholesale market until standard market design is achieved. While we're working on standard market design, a revised OATT that more effectively and efficiently utilizes ATC is needed now.

The Commission's decision to require a network interconnection service for merchant generators is an important step in the right direction, but it must be supplemented. For example, transmission providers should be required to post ATC values for both what is being studied and for what is confirmed for the customers. Transmission providers should be required to adopt transmission reservation redirection guidance recently provided by this Commission to SPP.

The Commission must break the transmission service study logjam that currently jeopardizes timely access to the transmission grid. A primary purpose of Order 888 was to rely on standardization in order to eliminate the potential to use delay to deny. The Commission should revise the concept of capacity benefit margin. The Commission should revise its rollover rights.

DENA believes that the revised tariff should require transmission customers to pay for the option value of their automatic rollover rights received today with annual firm transmission. Transmission loss methods should not create cumulative loss reservation requirements for customers and nonfirm transmission rights should be developed in a manner that maximizes the benefits to the market and yet still recovers the variable cost to the transmission providers.

DENA appreciates the opportunity to participate in this panel, and I look forward to further dialogue.

MS. ROSENQVIST: Good afternoon. Thank you for inviting me back here.

When I was asked to think about what changes were needed to the tariff, I asked myself, changes to accommodate what market. Michael just listed a whole lot of changes he would like to see that fits into a physical-type reservation, while we've been talking for weeks now about some type of financial rights market.

So before we talk about how to change the tariff, we ought to resolve a number of policy issues and a number of market-related issues. We've got to ask ourselves a series of questions, which I wrote down a few.

First is whether we will have an ICAP market or ICAP requirement. If so, whether ICAP must be deliverable. If it is, is the cost of deliverability upgrade rolled into the rates?

If it is, why would any generator elect an interconnection standard that doesn't make his unit an ICAP resource or network resource, as are referred to. If the costs are not rolled in, is it fair to charge the new generator for such upgrade? If it isn't, how do you then design a structure that doesn't put the latest vintage generator on the margin for transmission access? We have a whole series of questions to answer.

The second issue I thought about was there was a lot of debate yesterday about market-driven solutions versus regulated transmission. And we have to ask ourselves, market-driven solutions are generally paid by entities that see the benefits to those solutions. For example, of merchant transmission, either the locked-in generation may pay for those costs to see new capacity built, or the load that's paying high priced congestion negotiates an arrangement with some merchant transmission developer.

The question is, if the market-driven solutions are desirable over regulated transmission, which was a question we were struggling with yesterday, what type of market design would encourage these non-rate-based solutions without allowing elongated long costs to the customers or reliability degradation?

The third item I took a note for myself here was we listened this morning to a lot of discussion about ICAP and deliverability. We have also heard in the past few weeks about market structure in which self-scheduling is an important part of such market. And I ask myself, aren't self-scheduling and ICAP deliverability some kind of physical right? How do you then secure these rights? How do you buy them? What structure would be put in the tariff to allow purchasing these rights?

Those are the types of questions I asked myself, thinking broader to the restructuring of the market, what markets we're putting in place and then try to match a tariff with it.

For the discussion portion of this panel, I'd like to have an opportunity to throw some ideas out for a tariff restriction that would fit a financial market. It wouldn't quite work with a physical market. It might or might not, but I'd just like to have an opportunity to talk about it, and maybe we can have a discussion over it and see if it works or doesn't work.

Thank you.

MR. LUCAS: I'm John Lucas, manager of transmission services for Southern Company.

Southern Company does favor the idea of a new type of highly flexible transmission service that would better align the tariff with how markets operate today. One thing to keep in mind, and it's a critical principle we feel, you ought to make sure that the market model for a region is determined first before you go and try to make modifications to the tariff, which, I think, is similar to what Masheed was saying.

Last fall there was a workshop, and at the workshop, a lot of the panelists seemed to favor a new type of highly flexible service. They just weren't very sure about what that service should be. I think the thing we need to keep in mind as we design this new service is that the majority of sales today by many utilities involve bundled retail load, and so you're still going to require some type of network service to serve that load.

As we go forward and the Commission looks at this new type of transmission service, I think we ought to keep in mind the following principles. I'm going to go down through a few, and then I'm going to throw out an idea for a new type of service we've got.

Principle number 1, and as I said at the start, you've got to make sure the tariff is better aligned with how the market operates and focus on facilitating bilateral markets. You've got to design material with flexibility to accommodate all customers, whether they be load-serving entities, generators, marketers.

And I know it will come as a shock to some, but we think you ought to make the tariff accommodate timely interconnections and generate new energy resources. Changes to the tariff should certainly not result in significant cost shifts between various users of the tariff, and we need to make sure that you preserve any firm delivery service rights that existing customers have.

Going further, we ought to make sure that there's a secondary market for the resale of transmission, and then, a fundamental principle is we've got to provide appropriate short- and long-term price signals, including incentives for both expanding the system and making sure that we've got cost-effective location of generation. The tariff has got to better accommodate system sales from multiple generating plants. I think that's a real weakness in it today.

And now turning to my new product idea, quite frankly, it's no question, when generators come to us and interconnect, they're not sure whether they need point-to-point service, whether they need network service, or what exact load they will be serving at the time they make that interconnection request. The generator just wants a good assurance that there will be an ability to deliver the output of the generator to the grid.

I think our analogy of, to the grids is we ought to look at a concept that we refer to as hub transmission, and the idea of hub transmission is that the hub is effectively the network. And we ought to analyze deliverability of the output of the generator to the hub, and then customers can come and request service from the hub. And they can be network customers, they can be point-to-point customers, they can be customers trying to move power from an external interface, et cetera. I think it's somewhat analogous to the network service interconnection product that's being discussed and debated in the ANOPR right now.

With that in mind, I think some other changes to the tariff we ought to think about or just some things to keep in mind, if you try to adopt a single type of service, today there are disparities in the short-term acquisition rules between point-to-point and network. In other words, point-to-point doesn't have a contract to reserve capacity, and network does. If you're going to designate a resource as a network resource, it has to be an uninterruptible-type product.

Along those lines, customers who take point-to-point service, they can speculate on the transmission and, thereby, block the network customers from being able to utilize secondary resources and to fully compete in the short-term markets. Network customers cannot speculate that way on their network resources. They have to have a firm contract.

And to wrap up our changes, we ought to make sure we've got clear procedures for how load-serving entities reserve capacity for load growth. That is critical for parties that have a legal obligation to serve. Likewise, we ought to make sure the rules for how you reserve and utilize CBM, or capacity benefit margin, are spelled out in the tariff.

And lastly, there have been a number of orders on commercial business practice, especially Commission Order 638. We ought to make sure that those principles are delineated in the tariff, and make sure that we revise the tariff and provide clarifications on the sometimes confusion and chaos that surrounds rollover rights and redirects of existing point-to-point service.

Thanks so much for the opportunity to comment.

I look forward to your questions.

MS. KELLY: I'm Susan Kelly. I want to start off by thanking you for inviting me back. I very much appreciate it. I promise to keep all of my analogies G-rated this time around.

Last October, I appeared only on my own behalf, and I'm doing the same again. I want it abundantly clear that my remarks should not be attributed to any particular client I happen to represent before this Commission from time to time. Do not hold it against them.

I have tried to develop a consumer-side practice, so my personal approach to these issues is to try and look at it from what is good for an end-use customer, and the load-serving entities that are not-for-profit and are owned by them and, therefore, love them.

And in analyzing the issues, I understand you gave us a specific set of questions. I'm prepared to address those, but this is only my air time with you before you issue the ANOPR. So I wanted to get a few important points across.

In analyzing these issues, I've got to ask you to please look at it past the viewpoints of the various players who will appear before you and try, and look at it from the perspective of the end-use customers. We shouldn't do this for vertically integrated utilities or for marketers or for professors or anybody. We should be doing it for end-use customers. If it isn't good for them, we should not proceed.

I haven't seen any residential or small commercial customer clamoring at the door saying I want a big price constraint. They're saying I want reliable service, I want affordable service. How you choose to deliver that to them is your business, but that's what you've got to do, or there will be negative political ramifications that none of us want, neither you or the people that practice before you.

This is why alarm bells go off for me when I hear things about transmission rights have to be reclaimed from those who currently use them to serve load so they can be given to those who value them the most. This is why I'm concerned when I hear market signals that, you know, if you're suffering in an area of congestion, you need to pay, so that you know you've chosen the wrong place to live.

For the 90,000 customers who are co-op customers on the Eastern Shore, they paid a million dollars in congestion costs in January, the month that just passed. This has been going on for over two years now. That's a lot of bake sales, you know, in order to come up with the money to pay for the transmission or the other solutions that will relieve that congestion once and for all. So when I hear people say they just need to absorb that, market signal, there may be consumers out there who are unwilling to absorb that market signal, and you need to know that.

We filed comments, the TDU systems filed comments after the October conference. And we listed in there five things that load-serving entities such as the TDU systems took away from the experience that one of its members, Old Dominion, had in PJM.

Experience number 1, if you're an LSE and in a load pocket, expect significant congestion charges that you cannot hedge because of the simultaneous feasibility requirement. You cannot get enough FTRs, even if the auction -- you're allocated your pro rata share, there are not enough to go around, you can't get them, so you will pay congestion.

What FTRs you can get, you have to get, even if they're obligations, even if there's a slight chance you may pay out. You cannot miss the opportunity. You have to take them. Otherwise, you may end up short. If you're offered a choice of the actual FTRs or auction revenues, take the FTRs. It's a pig in a poke to take the auction revenues. You don't know if that's going to be enough to compensate you. Who knows? It may be more, but I highly doubt that.

The question is, will it be enough? Without vigorous cost mitigation mechanisms to prevent economic bleeding in load pockets, you can expect to pay congestion for months, if not years.

Like I said, it was a million dollars last month for 90,000 customers on the Eastern Shore. There are two possible defenses against this situation. If you're going to go forward with this market design, there are two ways to mitigate the situations we're describing. One, well-crafted price mitigation. You cannot assume, as Mr. Shanker said this morning, that the market is competitive and go from there. You have a due diligence obligation to look at that in advance.

If there are generators who enjoy market power in a particular region or subregion, in either ancillary services or energy or capacity markets, or whatever market you have, you have to mitigate that, starting out. That's your due diligence obligation.

The second thing is you have to have a construction of transmission procedure that works, and I think other people have alluded to that. I'm sure there will be lots of discussion of that this afternoon.

That's why I think that power market mitigation and construction are the two most important issues you have to deal with in all of this. If you don't, you're cruising for a bruising by implementing this market design.

I also find the ongoing debate about the existing wholesale contracts and how we've got to sweep away this impediment to competitive markets a little ironic. Let's go back to Order 888 where there were existing wholesale contracts that maybe customers were interested in getting out of so they could participate in the brave new open access tariff world.

We were told those contracts had to be honored for their entire term, and after the end of that term, we had to pay stranded costs because the other side of the contract had reasonable expectations that we'd be around for the rest of our lives to pay those rates.

Well, what are reasonable expectations if we hold an existing transmission contract and continue to enjoy the benefits of that contract past the end of the contract term? I'm not saying that that's the way it has to be, but I'm just pointing out that whose ox is being gored is a major, major issue when it comes to what do we do with existing contracts, and this Commission should rise above that and treat parties fairly.

You heard from Roy Thilly yesterday about what he had to go through to get his transmission agreement, and he's not the only one. There are a lot of war stories. A lot of blood, sweat and tears went into those existing transmission contracts at the wholesale level.

And I have to comment on this idea of auctioning the transmission rights to those who value them the most. How does this advance the ball for end-use customers? It's not like they're being withheld from them now. These rights are being used to serve load by people like my clients. And that's being done at regulated cost-based rates.

The auction is either going to cause us to pay more to get those rights back, in effect to keep them, or other people are going to get them because they can pay more than we can. And they're not buying them to mount them on the wall and admire them. They are buying them to rebundle them and get the money that they paid plus more back from load.

So somebody's paying for this, and I just want to let you know that they may value them the most because they feel they can get the most for them; whereas we're trying to provide service at the least possible cost, not the maximum profit. Thus, you have to approach this whole group of issues, what changes are necessary to the tariff, what happens to grandfathered contracts, what kind of translation of present rights to future rights go on from looking at it from this perspective of what does it do for load.

Now, it also suggests that you want to take these existing transmission customers and make them want this service. That's the way around preexisting contracts. It's the Tom Sawyer theory, make them want to paint the fence. They'll want to paint the fence if your service is good enough. I just want to make sure that we all know our goal here is to serve load, not create arbitrage opportunities.

Thank you.

MR. HAYDEN: I'm Jolly Hayden, vice president of transmission operations as Calpine. Thank you very much for inviting me here.

Calpine's position, and several of our contemporaries' positions, is we've got unbundled transmission service, that what we have today as bundled service is discriminatory. It's a second-class service, point-to-point, second class to network service, as we know it.

There's no real good reason to continue this, and the bottom line is if everybody is to operate under the same tariff, we all will benefit and suffer the same consequences and, therefore, will have more motivation collectively, all customers under that single tariff, to solve the problems that we all face, from supply side to load side.

This is obviously very consistent with what happened in the past with the gas model. Some of the key features are already being discussed right now in the ANOPR process. And basically, we want the terms and conditions that enable all customers to have access.

We need a congestion management system that allows maximum efficient use of transmission capacity, as well as we are very supportive of new rate treatments that reward expansion of the transmission system as stated earlier.

There's been previous panels that are saying generation solutions are generation solutions. The bottom line is we can't have generation solutions everywhere. We wouldn't have some of the problems we have in New York, as an example. What we have out there today, the transmission providers are not properly incentivized. In fact, I would argue they're at risk for making transmission upgrades. We need to solve that.

The other area obviously we keep talking about is market mitigation, and it's very difficult, it seems to me, for us to figure out who is really the cause of the market power abuses when we have a bundled up market. If we unbundle it, it makes things more transparent. It also, therefore, makes it more easy to determine where problems is.

A concern I have is we seem to be focused on the generation side of that. Market abuses can occur all up and down the chain. The concern associated with the market monitoring plan that has been proposed by several is that the market monitor is tied too closely to the RTO or the ISO. It needs to be truly independent so it can be unbiased as it looks at what is going wrong.

We've been in this transition period now for five or six years, and I remember at the seams conference in the late summer that now-Chairman Wood made the comment that we've lost a lot of money during the transition process, we need to expedite this. FERC found that transportation embedded within the pipelines offers to -- basically was a superior service and that we had to unbundle. What's the different here?

I look forward to the questions and the comments. We have a long list here of questions that you asked. Thank you for your time.

MS. ZIBELMAN: Again, I also thank you for inviting me back. My name is Audrey Zibelman, vice president for transmission for XCEL Energy, also, chair of the executive committee of TransLink.

Again, as many of the panelists, I looked at your questions and I thought that really what we're talking about is how do you create a workable tariff in a market environment and a market structure we want to go to. So the first question has to be how do we get to the market structure first and how do the tariffs facilitate us getting there.

With regard to that, then, I'm going to really speak in terms of the perspective of the Midwest market, as a member of MISO, and talk about what I think it's going to take us to get to a much more regional tariff design.

The first issue for me is, in terms of looking at the physical construction of the grid, where we're going from today in terms of the legacy system. The grids in the Midwest were not designed for superregional transfers. They're really designed to move generation to load.

What that means is, as soon as we move from what are really now individual system tariffs to regional tariff, we need to address issues such as the costs-shifting issue. We need to make sure that's embraced in the tariff design. We need to think about the fact that we need appropriate incentives to build transmission on a regional basis.

We also need to create incentives for companies to consolidate control areas and look for more opportunities to get more efficient operations that make it look like a broader region. And we need to look at the fact that in the Midwest in particular, it's been a bilateral market with a lot of firm point-to-point contracts.

I heard you -- I wasn't here yesterday, but I certainly was on the other side of the discussions with Roy Thilly, and they do take a long time to work out the terms of those contracts, and people are depending upon them.

The other piece is we have to recognize that if the ultimate solution is to get to a fully transparent and efficient market, FTRs are not a substitute for building new transmission, and that we need to make sure that we have -- that when we're going in and saying we want to build transmission, people who happen to hold FTR rights and have commercial advantage of them are not held superior to constructing new transmission which provides for more efficient markets. That's on one side.

On the other side of that in the Midwest is the fact that we are coming from loose power pools in which the merit order of dispatch is based upon individual utilities' desire to get generation, sort of their network resources. What that means for me is if we move to a more regional-type tariff, we're going to change the merit order for the dispatch. That means we need a compensatory mechanism for the retail customers who may be losing the advantage of some low-cost generation simply because of the change of merited order.

Today, because in the Midwest we don't have retail wheeling, many of us use the fuel clause to compensate for customers for different changes in merit order. We have no real mechanism through the fuel clause to compensate retail customers who may lose an advantage of some of the generation that they feel they have a first priority on, because we're changing the merit order. We simply need to discuss that and address that in the tariffs.

The other piece is that -- although I hear that in the East Coast, you don't have it -- integrated resource planning is still alive and well in the Midwest. We continue to file resource plans with our states and are continuing to look at building transmission and generation to meet local needs.

Any tariff that is going to create incentives to build superregional transmission also needs to take into account what the states' concerns are in terms of least-costs planning, and we need to have the ability to do that. Again, we think that ITCs provide that good bridge which will look at both the local needs as well as the superregional needs to build that bridge between what the states' concerns are and the creation of more wholesale markets.

The other piece that is a major issue for us in the Midwest is the presence of public power. When we formed TransLink, one of the major issues for us was dealing with the fact that in Nebraska, the utilities continue to need to have first call on their assets, both transmission and generation. And so any time we're talking about a superregional tariff and moving into a regional approach, we need to make sure that the concerns of public power are addressed, and that somehow or another we accommodate that, but we don't do that at the expense of investor-owned utilities or other players in a market.

Lastly, then, is where do we think we go. I also have a proposal that we've been thinking about, and it's very similar to the hub approach that Southern was talking about. We want to move, in the Midwest, from a series of markets that were based on the individual utilities building to meet their load requirements, to a superregion. To go from having individual utilities operating their system to a superregion the size of the Midwest ISO is a fairly large step.

What we believe is a good approach for the Commission to think about is creating regions within the Midwest ISO where, for example, in TransLink we were talking about consolidating five control areas into one, that can become effectively the hub of a regional tariff, and you can have a series of hubs in the Midwest ISO as we make this transition into a much larger region.

We think that in the end, to go from point A to Z, which is where you want to go in the Midwest if you want a market like PJM, you have to take some steps in between. And the idea of moving into smaller regions within MISO where you can operate these tariffs, we think, may be a good first step.

Thank you.

MR. ROSS: I'm director of delivery policy for Dominion Resources, and thank you to the Commissioners, and Mark, thank you for coming back. I'm responsible for state and regulatory matters regarding transmission and unbundled distribution service, including the development of in light of recent FERC orders modification 2, our RTO direction and participation.

I'm currently the chair of the SERC, EC energy committee and vice chair of the NERC planning committee. I participated in the standing committee representative task force that looks at the NAISB and the NERC reformation for standards process. I was a chairman of the PJM ISO members committee from April 2000 through April 2001, and I served on the USA advisory committee to the CIGRE national study committee for power system planning and development.

Dominion Resources, I still think, reflects really what is the new competitive industry for the integration of electricity/gas operation for this country. Our trading desk sells all fuels, gas, coal, oil, electricity. And the whole distribution chain, when you look at the fossil fuels that we sell, to me represents Dominion as much more of a national company. We have SNFCA and gas resources with the acquisition of Louis Dreyfus. That substantially increased our gas portfolio.

In addition, we're a diversified national company thriving to get our fleet of generation that we own around the country to market. And I'm not as familiar with the hub concept on transmission pricing. I certainly don't have as many developed ideas on that, but I think it is certainly worth exploring.

The current rules of the game don't allow Dominion to get its fleet of generation to market, and the way in which point-to-point service is working -- and Jolly Hayden spoke to some of those issues -- in order for us to get our fleet to the market and create what we believe is a truly national market and supply is, I think, going to require fairly substantial modification to the pro forma tariffs as they exist, and we are here endorsing that reform to transmission pricing.

We need to get some certainty in the ability to have our energy delivered to market. We need to have some ability to have our capacity recognized by the market as a marketable commodity in the financial sense, while at the same time we still try -- and this is a tug and pull inside the company -- to look at a successful stand-alone transmission entity.

We really believe that investment in transmission is part and parcel, even though we don't have integrated resource planning. We still look at an effort to provide the right kind of a plan with generation and transmission. Standardized delivery tariffs really will help us get that national fleet to market.

I think the other side of it, though, is the capital markets balance risk and return. It's simple, access to equity and building new infrastructure really needs to remain balanced or we're not going to be able to build the transmission necessary to get the generation to market. So whatever standardized delivery tariffs we create cannot create a balkanization.

It does not give me, as a transmission provider and delivery company, access to the capital markets to build new transmission improvements. So I think as we move forward, this is not a go slow caution, it's a go quick caution, that we need to reform transmission pricing so I can get access to capital necessary to build the transmission grid to support the new market design.

The final statement I have -- and I guess I told Sue Kelly before we started, that it's unfortunate we were on the same panel because I enjoy listening to her speak. Sue, I listened. I'm debating where to use my ending -- that the transmission service business and the standard delivery tariffs and rules should give transmission owners the incentives to give new and enhanced services to their customers, which we consider to be generators and the load-serving entities. Even though our mechanism to get there may not be similar, I think our goals to get there are the same.

Thank you.

MR. WHEELER: Good afternoon. My name is Steve Wheeler, senior vice president at Arizona Public Service Company with responsibility for transmission operations, regulation, and planning. I'm also a recovering lawyer.

APS is one of the West Connect applicants. And so I speak to you today both on behalf of Arizona Public Service Company and West Connect. I also send you greetings from Phoenix where it's 70 degrees, where we have lots of inexpensive but very good hotel rooms. The Mexican food is spicy, and the drinks are cold, and we invite you out for a regional meeting sometime before it gets too hot.

CHAIRMAN WOOD: Sold.

MR. WHEELER: Before I give you a brief summary of our responses to the specific questions that we were asked, I need to do a little bit of a press release on West Connect because it helps set the stage for our perspective on these issues.

For the last five years, we've worked together to put together an RTO that we believe meets all of the Order 2000 requirements. This process worked us through an ISO to what has now become the West Connect RTO, which is a for-profit Delaware series LLC. That's a fairly complicated mechanism, which I won't describe, but its prime advantage over other RTO structures is it provides significant membership flexibilities that we can accommodated all the different types of market participants that are necessary to make an effective RTO.

Our structure and our governance and our comprehensive protocols may not look like PJM. They may not look like MISO, but we believe they work, and they reflect the significant structural market and participant differences that occur in the western utility markets.

But perhaps even more importantly, it reflects a consensus, a broad-based consensus among all of the market participants, stakeholders, customer groups, generators, marketers, transmission owners, and the like, a consensus that was very difficult to achieve, and as I say, took almost five years. That consensus is perhaps even more important in the West Connect area, because almost half of the West Connect transmission-owning entities are nonjurisdictional entities, like Salt River Project, Western Area Power Administration, and the like.

These are folks that, like it or not, you don't have the same ability to regulate and to dictate to. So getting a consensus with these groups is very, very important. Otherwise, you're going to have a Swiss cheese RTO that simply will not function well in the west.

My message to you is that the West Connect applicants support RTOs. We're firmly committed to getting one that works and works right. We support your approach to standardize market design and market structure wherever you can in a way that is reasonable but also reflects regional differences. But we ask you to be flexible to deal with the fact that we have a consensus that was hard-earned and which, if you try to tear apart that consensus and the stakeholder process that produced it, you're going to do great violence to the effort that was made, and ultimately, you may have a very unsuccessful situation.

In that regard, we also ask to you give recognition to the efforts that have taken place. One of the state regulators I used to practice before said he thought he had done his job if people were sullen but not mutinous. And I would in one sense ask you to use that same standard with respect to how you treat the West Connect applicants.

So with that, let me briefly summarize our response to the questions that were posed to us. The section A questions dealt with updating the pro forma tariff. If by that the first question you meant that every generator should have access to all loads, no matter where they are, all the time, then we disagree with that as a concept to work toward, because we believe that would be exorbitantly expensive to construct all the network upgrades and new facilities that would be required to provide that kind of service to everybody all the time. And we would suggest that is not necessary, at least in the West Connect area.

We have many merchant generators that are siting in Arizona, for example, who have no intention, no announced intention of selling into the West Connect regional area. They're selling into a different market. So providing them with the opportunity to sell everywhere in West Connect is not necessary.

It also disregards the fact that many of the nonjurisdictional public power entities have to heavily rely on the existing contract paths. If you start making those more difficult to utilize for their committed and statutory obligated service, you're creating a new area of difficulties. As you know, in the West or at least in great parts of the Southwest, you've got radial connections between large load centers and very remote generation. So you're further exacerbating the problem.

On the other hand, we do agree that you should continue to have both point-to-point and network service in the RTO, and in fact, that's what West Connect provides for, and we're also working very hard on seams issues, to make sure that service wheeling through or wheeling out can be easily accommodated with neighboring areas.

The questions that were asked about how to calculate ATC and TTC seems to raise two different issues. One, should it be calculated regionally? And we believe yes, absolutely, to the extent that can be done, and that you get the input from all the affected transmission owners and other participants in doing that. But the other question was, should it be done independently? I'm not sure I knew what it meant, if it meant the RTO. We absolutely agree it should be and West Connect provides for a method of calculating that.

I will tell you if you meant something other than the RTO or even if you meant the RTO, you need to recognize the fact that many of the nonjurisdictional entities have statutory restrictions or otherwise feel strongly that they will not cede too much control over the use of their systems. So you have to be careful what kind of review process there is in the ATC and TCC calculations.

You need to make sure that you take into account the input and knowledge of the transmission owners who had the best information on the capabilities of their system, and you need to consider who is responsible for the liability that results from misprescribing those. That also can be an issue.

The second tranche of questions dealt with transition to a single tariff. In that regard, we don't believe you should depart from Order 888, which, at least as I read it, said there would be no generic abrogation of contracts, but at least there was the opportunity for people to present issues on a case-by-case basis, although they would bear a heavy burden of proof.

We believe you need to honor existing

contracts, because at least in the Southwest and West Connect area, oftentimes those contracts are intertwined with both transmission and nontransmission services and activities that cannot be easily separated. So just to tell somebody that they have to take out the transmission portion of a very, very complicated contract and subject that to certain tariff provisions while leaving the rest of it intact could do great violence to the purposes and intent of the underlying contract.

In addition, and perhaps from our standpoint most compelling, many of the nonjurisdictional entities simply would not and will not agree to that. If you have to have harmony in the west and not have range wars, at least those views need to be -- at least be considered.

Finally, I think there are also legal issues associated with the abrogation of contracts and what happens with respect to the takings issues and the like, and of course, you've also got state public utility commission issues, because in many cases, some of those contracts were either ordered by or are currently reviewed and, oftentimes, proved by those state commissions.

Nevertheless, we do understand the issue. West Connect has a conversion process in it. In fact, the West Connect participating TOs have all agreed that with respect to their agreements with each other for transmission service, those will all be converted to the RTO tariff. We have categorized the other types of existing contracts in our tariff and have provided provisions where we tried to create incentives for people to convert by making sure that there are appropriate transfer payments and sharing of any congestion revenues.

I thank you very much for being here, and I do hope you'll consider my offer to join us in Phoenix some time.

MR. HEGERLE: Thank you all. Since we have complete consensus, I guess we're finished for today. The Staff paper sort of proposed a transmission service and several of you offered up some ideas on what you feel transmission service ought to look like.

I wondered if I could have you go down the line and address what we said in the Staff paper, which was -- I think Steve mentioned it, the idea of every generator -- every load being able to reach every generator. We didn't mean it quite the way Steve mentioned it. The basic fundamental tariff system we wanted to set up was something along the line of PJM.

I would like it if you could give me some thoughts on that proposal. And if you have come with a different proposal, as I know several of you have, if you could compare, contrast, and let me know if what we're talking about meets some of the needs of what you're looking to do or how they differ.

MR. GILDEA: The concept of having a generator be able to get to the loads in a market area is extremely important. We have been fighting a merchant generator, since the time I've been at Duke, blow by blow trying to get that access. A generator can't have access to everywhere in the entire network without appropriate study and appropriate upgrade on a comparable basis, but it needs to be -- it's definitely a step in the right direction.

I would also make the comment that we are suggesting problems on the other end of this getting what I'll call "network service" off of loads surrounding that generator. So it's not just a matter of getting the generator connected into the grid with some kind of network service, but also when we go out and have our origination team find customers that want to be served by that generator, we're experiencing snags in identifying that generator to get the network service.

MR. HEGERLE: Are you saying the generator's trying to get generation service or just can't be designated as a resource for that particulars service?

MR. GILDEA: The person who is doing the network study, et cetera, is a competitor. Essentially we're going out and getting customers of the person who is doing the studies -- and there's a huge conflict of interest there of having comparable, efficient process, because essentially, as our study process proceeds, it's only a harm to his pocketbook. It's not just an issue of getting a merchant connected in on a network basis but the whole transmission access issue.

MR. HEGERLE: You want to see that be done independently, separately as well?

MR. GILDEA: Well, side by side. To get a generator connected on an integrated basis is not going to solve a lot. The generator has to be able to get connected to the grid, but your whole transmission study request process also needs to be efficient so that you can on a daily, weekly, monthly basis or whatever move the energy.

MR. O'NEILL: Can I get a clarification? Are we talking about the second question in the Staff piece, should we modify this to get the transportation service similar to MISO, PJM, and New York? Are we talking about getting that kind of transmission service or the transmission service under the current 888 tariff? I heard a lot --

MR. GILDEA: It's a very gray line. I believe that the world we're in today and the markets in the

Midwest and the markets outside, the free-type polls today is an Order 888 world, and I think we need to have -- the problems that we're facing today are today's problems.

So I think we need to set up this tariff with maybe a lot of the principles I hear from other people at the table and move forward with today's OATT and have it work for it and address the problems we're experiencing today. We also need to be cognizant of the fact that we need to blend over into the standard market design LMP world in the future. So it's a blend of the both.

We really need to have addressed the problems we're experiencing today because a lot of the markets I'm in, we don't see the standard market design that's experienced in PJM being implemented until three or four years out. So you're not going to stay in business that long. So we have to fix the problem we have today and yet make sure that what we design is consistent with what's being implemented in the Northeast in the future.

MR. ROSS: I like to look at Dick's question a little bit differently than the way you responded. I, for one, am not so -- I guess I'm a recovering mutinous, based on the recovering lawyer over here, being in the Alliance.

MS. KELLY: Are you going back to sullen? Is that your point?

MR. WHEELER: I withdraw my analogy.

MR. ROSS: I don't think the comparison was the right way to approach the problem. I think if you hold on to the past for far too long, you repeat problems of the past. I wouldn't ask the question the way you asked the question. I would say what investment in transmission is required to support the network design and how should delivery services be priced to achieve that goal.

The three legs of the stool are ANOPR, tariff market design. I have an expectation following the October RTO workshop -- and maybe I'm wrong -- that we're moving this thing forward fairly rapidly, standard market design. There is an expectation that a rulemaking may be out before recess.

Now, maybe I am totally off the wall, but you can't be slow, and you can't necessarily grab 888 along with you when you're moving down this path. So I guess Dominion supports a movement to OATT. I think the concept of network design for all load is proper, and the only point-to-point reservation I have is the point-to-point service may, in fact, be a service that is held over when a customer wants something fairly simple or a customer wants to move from an RTO to an RTO or from a hub or some kind of pricing mechanism. If a customer wants that service, it shouldn't be taken away from the customer.

I think the next step, then, in any new pricing is to define the constraints that prohibit you from moving to the pricing, and I thought the paper did a fairly nice job of trying to begin the process of identifying what constraints, such as existing established contracts, kept us from moving. But I don't know that we ought to define those constraints in light of Order 888 as much as define those constraints in light of the standard market design. That's where I took a little different issue in approaching it than Mike did.

MR. O'NEILL: That's the question I was trying to ask.

MR. LUCAS: I know Masheed wants to talk, too. For my simple mind, I have to jot things down.

Mark's question, should we create a tariff product that lets all the generators reach all loads, as you well know, that's kind of the heart of the network service type under the ANOPR.

I think we're going to get there, and I can't speak from a complete knowledgeable standpoint about what's done in PJM, MISO, and New York. I would just say that I don't really want to adopt that one size fits all approach, but the interconnection ANOPR product will, in effect, get you there. It will be an interconnection product that, if studied correctly and paid for appropriately, will allow the generators to reach the loads.

Now, one shortcoming -- and you've heard this before -- a shortcoming is that the pricing has been relegated to a second phase, and we've been unable to deal with that issue as we design the product. The product definition is fairly fleshed out. I think it's descriptive. I think it gets the type of product you want, and I don't think you have to have a specific linkage to an existing type of market. I think it will work with most market designs.

I would just be hesitant to shove a PJM/New York/MISO market design approach in as a tariff product. I would stick with the interconnection network service product that's being furthered through the ANOPR and let the market design around that be a little more flexible.

MR. HEGERLE: Don't you need some kind of pricing/congestion management system to get you -- get the access that we're talking about?

MR. LUCAS: To me, it's not required. It's not required, because again, what the interconnection ANOPR is going to lead to, it's going to tell generators if they've located in the most cost-effective place on the transmission system with respect to is it cheaper to build transmission to get that generator to a load pocket, or is it cheaper for the generator to locate next to a gas pipeline and have long, expensive lead times on transmission.

To me, it will address that, because when the generator comes in and he asks to be interconnected, the answers from his studies, if he wants to be a network resource, if he's in a bad place, the transmission price signals are going to tell him that. To me, it doesn't have to be linked to congestion.

And Mike is saying, it's going to take several years before you've got a fully fleshed-out congestion management system in other places, even if it's a pure adoption of PJM. It will just take time for those markets to implement that. I don't think you want to wait that long.

MR. O'NEILL: Are you opposed to the standard market design in the Staff paper?

MR. LUCAS: I wouldn't say I was opposed.

MR. O'NEILL: So you support it?

MR. LUCAS: You've tricked me on that now, Dick. What I'm saying is just stay flexible. I think you don't want to make the features of the market design so tight that you can't have other alternatives to the type of congestion management system you have in PJM.

CHAIRMAN WOOD: So your concern really is more of how long the sequencing period would be, and I believe Mike's problem is don't wait to get to nirvana and you can get to MISO paradise before then.

MR. LUCAS: Yes. Sequencing and pricing, those are the two I would say we need to get right.

MR. WHEELER: Mark, one of the things that make us less enthusiastic about switching to this type of tariff -- and it has not been an issue in our stakeholder process -- is we may be doing something that the other RTOs are not. We have load -- the transmission rights go with the load.

So if we have a merchant generator that wants to sell into our system and is selling to a marketer or somebody who is serving retail load, the transmission goes with the load. It doesn't stay with whoever was the entity that was previously selling to that particular customer, and that prevents hording and makes it a lot easier for people to get into our system.

With respect to Mike's Duke operations, they've got a plant right out near Phoenix that is going along quite nice and has been complementary of our interconnection process of getting into the hub. I think one of the reasons might be is. They know they are going to sell into our area, they will get the network resources that had previously been used to serve whoever was the generator using that load.

CHAIRMAN WOOD: What's the reaction of the rest of the panel to that concept of the network transmission rights follow the load?

MS. ROSENQVIST: Your question of whether we should change the pro forma to just match the PJM or New York ISO tariff and the concept whether network load should have the rights and have access to all generation gets to the heart of an issue, that your assumption is that the grid is capable of reliably delivering every generation or an aggregate set of generators to an aggregate set of load, which is the PJM deliverability model.

In New York and New England, however, generations are getting connected at a much lesser standard of connection. So you end up creating locked-in generation or a higher magnitude of congestion, and those are the -- that deliverability test is causing the major difference between the PJM model and the other northeast ISO models.

So if you're going to drop the whole concept of a transmission service in those physical areas and you want to give the right to load to have access to every combination of generation, then you have to make sure that during the generation connection study phase, that you're accommodating sufficient transmission to allow an aggregate of a set of generators to get an aggregate load.

The questions that I asked at the beginning of this panel discussion was how do you then price these upgrades that, one, doesn't put the new generator on the margin for access to the transmission, and two, creates enough incentives that in the ANOPR you have given a choice of an energy resource or a network resource. And if you don't want to put the generators on the margin, then you say roll it all into the cost of the rolled-in rate. And then, what incentive do you give the generators not to pick network resource and pick energy resource? What does that option really do you for you?

So maybe there is an answer between, that you pick a lower standard for connection, maybe like the minimum interconnection in New England, and then say if you have to sell an ICAP market or self-scheduling, both of which -- the ICAP sound -- deliverability sounded like a physical right this morning. The more I listened, the more it sounded like it.

And so is self-scheduling. If everybody decides to self-schedule their generation, how do you -- and you run out of sufficient transmission capacity, how do you prioritize them? One answer may be auction transmission rights to every generator, not the new generators to get on the system. You set up a minimum standard for everybody, and then if you want to sell ICAP or you want self-scheduling, you charge a secondary physical right-type thing, you sell those rights in an auction.

What you do with those revenues? You can either give it to customers who pay for the rolled-in rate or you -- in regions like New York that -- nobody wanted to talk about New York City this morning -- but where you have allocation issues for transmission funding, maybe in those regions you fund new transmission through those revenues. That way, you may actually put all generators on the same footing, and at the same time, give additional priorities to those who see the value in the market and are willing to pay for it.

MS. KELLY: The first thing was you asked a question. I wanted to make sure I answered your question. Could you restate your question? I think it had something to do with rights following the load.

CHAIRMAN WOOD: Right. What is your reaction to what Steven said about having a -- basically the network service of 888 follow the load to whomever -- to whichever resource or group of resources serves that load?

MS. KELLY: Yes, I love it. Let's do it.

MR. HEGERLE: Could you be a little clearer?

MS. KELLY: I would also like to throw a lifeline here to Mike, because we are having substantial problems under the OATT. I tried to think about what problems we're now experiencing that would be obviated by moving to an RTO tariff. I didn't think in my wildest bad nightmares that it would be three to four years and that we need to clean up the OATT now in the regions of the country that don't have an RTO.

He's right, it's a substantial problem; and if he's right, it's going to take that long, we do need to deal with those issues.

CHAIRMAN WOOD: What I heard, though, is something like that is going on out in MISO. On day 2 you get the more full-bore consolidated control areas, and you've got broader regions that do balancing and imbalancing stuff. All that stuff happens on down, but you do have an operational shop on day 1.

I think what we need to hear from you all here in this panel is, what in the tariff, that we've all lived under for five or so years, needs to be fixed so that we can start actually on day 1 other than the things, that like the software panel is going to tell us takes time?

MS. KELLY: Two things that have been the biggest burrs under the network service complaints that I have has been energy imbalance, number 1, where they are required to pay various owner imbalance charges while the control area operators are allowed to clear it through inadvertent interchange. Now, our hope was, we go to RTOs, and that's over. As we move to multiple control area RTOs, I'm afraid that's going to slip back in in some way, shape, or form.

CHAIRMAN WOOD: Look how PJM West has addressed that issue. I haven't got involved in that. Somebody here may know how that is working exactly. It sounds like they may have been able to get around that.

MS. KELLY: I certainly hope that's a day 1 or day 1.1 function, that we get that dealt with sooner than later. I think that's probably been the biggest problem.

COMMISSIONER WOOD: Actually, in ERCOT, Mr. Jones mentioned at our conference last week, that was the main reason they did that, because they couldn't resolve it.

MS. KELLY: And he was afraid he was going to upset some feathers if he said that, and he didn't upset mine. He's absolutely right. How do you deal with the whole issue of new transmission?

Ms. Rosenqvist mentioned you have new generators that want to be connected, but it's also going to affect new load as they get interconnected because our requirements are increasing. If you're number 6 in the queue, and you come in and say we can serve 1 through 5, but you, $90 million upgrade, that's not rational.

That gets me back to the best way to resolve that is through an RTO transmission planning process that works, that's timely, that takes into account the needs of all customers to make sure the transmission gets built.

I'm not against incentives, but I want to make sure they're needed incentives. Let's not give 16.5 incentive rate on return of equity and hope they build. Put it out for bid and have them build it.

I know there's eminent domain, state law problems, permitting, and all those things. We've got to be able to build new transmission if that's what the planning process determines is needed.

MS. HAYDEN: I will try not to be repetitive here. Calpine shares a lot of the concerns that Michael mentioned from DENA's perspective. This whole industry is in a critical mode here with the chain of events. To paraphrase again, Chairman, what you said last summer is we've lost a lot of money, this industry, during this transition. We've got to move forward.

Susan basically brought up the concerns she had from the FTRs, being on the East Coast and all that. Calpine is very supportive of basically monetizing all these FTR rights or these rights. Let's monetize that.

And I would suggest, what we do with those revenues, do you throw it back to the load-serving entities, original rightsholders? Susan's concern is that won't properly fund congestion. That tells me we've got a transmission problem, which then gets to what Susan was talking about, and everyone else including myself, we've got to get the incentives right so we can upgrade the grid. We are way behind in the upgrade of the grid, and it's showing.

In one of the panels earlier today, they talked about -- on the generation panel -- was the blackouts that occurred in PJM, and he's saying does that mean the ICAP market's not working. The question I have is, how much of that was generation inadequacy and how much was transmission inadequacy? We've got to work on that.

Some of the areas that, I think, have limited access is CBM. One of the questions you asked was CBM. CBM, I would argue its day is done. We have now more generation popping up in all the existing control areas or the RTOs, soon to be. They have more choices as it becomes reliability to pull from. They don't need to block interface, valuable interface capability to do that. In fact, they have a higher probability of being on a supply -- under emergency situation right there in their own backyard.

MR. O'NEILL: So as not to be confused, let me ask you the same question that I asked John. Do you do this in the standard market design context?

MS. HAYDEN: I guess again it would -- if you do it in standard market, I think it would increase liquidity, which reduces volatility, which, I think, will increase reliability. So I think it is fundamental. I think its day is done.

I want to make sure I didn't misunderstand, the regional calculation of the ATC and the rights, I think the bigger region we're looking at, the more accurate the information we will have. We still see today a disconnect when I'm looking at going from north to south at the same interface from the guy on the north side of that interface from the guy on the south side. It's not a factor of 10 percent. It's 300 percent sometimes, and you know, that is confusing market signals.

We are seeing ACT posted and we're first in the queue, and then we're getting denied. We're seeing zero ACT posted. We go ahead because we don't trust them. We put in our request, and surprisingly, we get accepted.

MR. O'NEILL: Can you calculate ATC with an amorphous network service requirement, or do we have to become more specific about what the network service requirement is?

MR. GILDEA: I think to add to Jolly in his introduction and, Dick, in a lot of your questions, one of the problems we're having today is in the 888 world three-quarters of the transmission doesn't live in that world. It's all in a network native bulk. Companies like Jolly and mine, we have to live in the slice that's left, and all these rules that we're talking about, et cetera.

In the standard market design world that I think a lot of us believe we're headed toward, everybody, all service is done equivalently. So we have this disconnect now where we're trying to tweak what we're doing -- I had a long list of items before you came into the room. These are all little details to tweak what I call the 888 world to try to get us through to the future world.

But the bottom line is if we could -- to me, if we could get everybody on the same tariff, then all of a sudden, your incentives are lined up, the incentives you're talking about are all going to be working because everybody's going to be in that room working to get the same solution.

I participated in the SPP RTO two years ago, and I believe RTO failed in large part because at the end of the day, 90 percent of the load wasn't on the tariff. I believe somewhat, on the MISO, the verdict is out. I believe the Commission gave a live decision about how they wanted to vote on that, but now we're seeing grandfathering and everything else erupt.

I think the jury is out on that RTO. Until we get everybody aligned, working on the same tariff, all these issues that we're talking about are going to be a problem.

MS. ZIBELMAN: In terms of what we should be doing and whether we would support a flexible network tariff and allowing net load to pick generation, we think that makes sense, and that's where we need to get to. The practicality of it, again, is that it's not going to be very feasible to do it in a region that wasn't built to accommodate that until you address the deliverability issue.

The objective will be to get the generation to the load. Consequently, as we're addressing that, we also need to address the incentives in building the transmission.

The other piece in terms of the hub, when we say network, it would be helpful for the Commission to define how big a network we're going to be looking at. Is it going to be all these interconnects or a subsubregion of it? That will help you define what kind of additional investment you really want to put in.

The other point is when we're asking whether or not the network transmission should follow the load, I think that makes sense, so long as we're talking about the existing footprint. The question is, when the load designates a new resource, what type of priority should that have over the new resource? Should they have that in advance of someone else who might have had a preexisting point-to-point transaction?

We would think in that circumstance, as least as an interim step -- and I have to look at a concrete example. If the load in Milwaukee wants to suddenly designate a new resource in Manitoba, should they have priority over AFC in terms of someone who has had a point-to-point contract that's existed there for 10 years.

I would think, in those types of circumstances, you can't deny the point-to-point -- the benefits that they've had until we get to the point where we're building additional generation and transmission.

MR. O'NEILL: How do you feel about Sue's suggestion, that we put the transmissions upgrades out for competitive bids?

MS. ZIBELMAN: I don't know if that's the most efficient thing to do. What we're proposing is -- we have a system planning process, and you have transmission companies that are in the business of wanting to build transmission.

What we'll be looking at is we'll do the system studies and say what is the best thing to do to meet the demands of the marketplace, and those system studies and what facilities we could put in place, and it's not necessarily new transmission. As we've all talked about, it could be reconducting, it could be putting in phase shifters, it could be raising lines to increase throughput.

All those options would be studied by the transmission provider, and then that would be put into the RTO process to determine whether that's the best solution. I don't see any of this happening in a blind way, but to say somebody would put it out to bid and the best bidder gets it is not necessarily going to be the best solution.

MR. O'NEILL: And why is that?

MS. ZIBELMAN: I'm not sure if the bid process -- bid processes have not historically worked the best. What you need is a good planning process where you have companies or participants looking at the various -- lots of responses.

Let me tell you what I'm thinking about. You have a transmission company who is going to be looking at what are the needs of the system. They will put together a systems study and facilities study, and submit that to an RTO and say here's what we think can be done to cure the problem. Then it should be a systematic process of saying is that the best solution.

MR. O'NEILL: And then have a competitive process?

MS. ZIBELMAN: And it could be a competitive process after that.

MS. KELLY: That was my point. After you go through the process and you get to what is the solution, then allow people to bid to provide that solution.

MR. ROSS: You just stole my thunder.

When you go through the process of the RTO protocols, it calls for a stakeholder process. Getting all of the owners and nonowners to air their solutions, and you choose the process, then throw it to the bidding process. It is an absolutely correct way to do things.

I don't know necessarily that the owner without the most competitive bid to meet and solve the problem coming up that was solved by the stakeholder process, if the owner can't meet that bid, they shouldn't be the one to supply the solution.

Back to the Chair's original question on load paying for transmission and all incremental is done in short-run marginal cost or cost of congestion, I really think that will work for a short period of time. I don't have a big problem with that in the short run, but it does fail, or I fail to see how that supports the long-run investment that's necessary to support the market.

Now, I think the Staff paper did a pretty good job of looking at the expansion cost allocation plan, and I'm willing to look at that as a very good -- I don't know if it's as mature as a straw man, but certainly a very good starting point to say there should be a cost allocation where you match some of the benefits of the stakeholder process to the implementation or the funding of whatever plan is built.

So I guess I'm not in favor of load pays and that everybody uses the system at short-run incremental congestion costs. I don't think that's a good investment decision for the transmission system, long-term. It's okay short-term. And in a situation in PJM where you've got 35 percent reserve margin, it might be a long-term solution. In my area where we've got a 12.5 percent reserve margin, it's not a good solution.

CHAIRMAN WOOD: Well, then, what is a good solution? You referred back to the Staff white paper. Honest to God, we've got about four running around.

MR. ROSS: In the short run, where delivery services are scarce, therefore you have high nodal LMPs, and whether you have 4000 or 300 LMPs, I still like the

LMP approach. In the short run, you do, in fact, collect from load the network service rate. And in the short run, for the congestion management, you do exactly what you suggest in the questions, and that is, allow for the short run, incremental congestion cost to be the cost of service.

But what you need to do next and, I think, some of what the Staff has done to look at the transmission constraints and identifying the 16 points around the country and then further identifying what those costs are, congestion, and how those costs are passed through and how we ought to look at further improvements to the transmission grid, you look at the Staff's paper for today's panel, and they have that section on allocation plan where the customers or load that benefit from transmission buy that transmission.

Today, if the improvement is required in Virginia, then the Virginia customers pay, even though the benefit of that improvement clearly flows through to the Northeast. So the allocation plan in this particular Staff paper says that the Northeast pays, but then the Northeast needs to be involved in the stakeholder planning process as a solution to relieve the congestion.

Maybe it's a hybrid. Maybe what you do is work up against congestion. Some congestion on the system is economic. Economics 101 says you've got to have congestion or you've overbuilt your system. So before you get that big improvement, allow this work, but don't shut this one down in favor of -- I'm not saying never. I'm just saying use it, but use it when you need it. Go to the Staff paper and figure out who benefits, let them pay.

The only shortcoming there, in my mind a shortcoming that you're using Virginia land, you're using Virginia resources to benefit the Northeast, and I'm not sure how Virginia's going to like that.

COMMISSIONER WOOD: In general, though, is it so necessary to pinpoint that direct link of that benefit? We got a nice feedback from the New York conference last week. Somebody said yeah, you could do the Connecticut one all by itself, but if we did the Connecticut fix at the same time we did the Boston fix and the Maine to New Hampshire fix, everybody realizes that in general, over time, all transmission upgrades kind of equally get spread over everybody.

Do we need to go through this mind-numbing exercise of saying I'm building something that improves this part of Virginia and benefits that part of New York?

MR. ROSS: I wish I could say no. In the buildout, I think you're right. But in the short term when you're trying to reach this new profile for regional markets and a single standardized market design, then the tariff reform needs to take into consideration some generation so somebody's ox doesn't get gored.

It's clear you could go back to the Staff paper on the transmission constraints and identify the existing constraints that maybe were built up over time and let those states pay for those, but I don't have a solution for you for that.

MS. ZIBELMAN: If I can respond to just that last question, one way to look at it is there is some transmission that we would call more the larger transmission that serves regional that ought to be allocated. But I think we can also recognize that there is transmission that's built discreetly to serve load or discreetly to serve generation and that there are different rate designs you can use to accommodate those differences in the use. It's not a single solution for all pieces.

CHAIRMAN WOOD: In a transmission tariff, is there superregional transmission separate from local transmission?

MS. ZIBELMAN: The rate design that we're proposing has transmissions that are used for supply and then what we call regional postage stamp transmission and transmission to serve load, and that addresses the difference. It also provides an equalizer for any new generation. They pay the same rate as the existing generation in a particular supply zone.

MS. HAYDEN: Can I ask a question directly on that issue. On the superhighway here, the 500 kV system, in order to get the throughput higher on that, you've got to upgrade subtransmission, which was actually built to serve local area. In that example, would that be covered on what you've described?

MS. ZIBELMAN: Yes, it would. What we've done in the superhighways is that we've done engineering studies, so, in fact, it covers a portion of what you would call the superhighway that goes into the regional rate. It's only if it's truly local that you would put it in the local. So it makes sure there's no free ridership.

MS. KELLY: I'd like to respond to this issue about this double-decker transmission rate design. You have to be aware, when you do that, you are in effect reinstituting pancaking for a different set of services or facilities, but that will bias people toward using generation that is closer to them and thus will not require the superregion rate, and that goes back toward reinstituting generation.

CHAIRMAN WOOD: I thought the assumption was the superregion rate is paid by everybody. So instead of it being 2 cents for everybody --

MS. KELLY: That's even worse.

CHAIRMAN WOOD: Everybody pays 1 cent, and if you're over here you pay an initial 1.2, and as usual over here you pay just a .8. So it was a slight deaveraging --

MS. KELLY: We have favored postage stamp, stamp to the greatest possible extent and the roll-in of all facilities as possible. Especially that last is not in the RTO because it's not in the RTO rate either, then we get back to our concerns about transmission market power. It's the local incumbent transmission owner/generator who controls that last stretch of line that gets us to the grid. We've had concerns and problems about that in specific RTO dockets.

So I wanted to caution you that that's not necessarily --

COMMISSIONER WOOD: That is not a control issue here.

MR. ROSS: It's a rate issue.

MS. KELLY: I would want to examine any such proposal very carefully. I would expect no less.

CHAIRMAN WOOD: Good. We're counting on it.

MS. ZIBELMAN: In any transaction, there's a piece of the tariff that you're paying for. It's not pancake. It's just recognizing that the transmission system serves different purposes, and you should always pay for the supply load and highway portion.

MS. ROSENQVIST: Just to clarify on that slice and dice of the rate design, parties get into long, long debates over where to slice that regional, local versus highway design. So we've had that in New England for years, and we settled it somewhere in there. The debate isn't over.

The second point, I'd like to go back before we all decide that transmission is going after competitive bid, I want to ask a couple of questions of Dick whether he meant just for construction or you meant ownership as well?

MR. O'NEILL: Either one seems okay to me.

MS. ROSENQVIST: So if you're sending it out for competitive bid for ownership -- let's stick to ownership. For construction we routinely do that, but for ownership, does that mean, then, the local transmission provider is no longer under an obligation to build for anything that the system needs? What is going to happen is all the good stuff, all the valuable stuff that merchant transmissions will take over and all the stuff that's perhaps too early for reliability or not much profit involved, they're going to ship it to the local, and why would we want that kind of a system?

MR. O'NEILL: You could be a merchant, too.

MS. ROSENQVIST: I know I could. That was my next question. Does that mean, then, the local providers are no longer bound by regulated rates? If you're sending these for RFPs, is then my bid in the rate, or is it a cost that's in the rate?

MR. O'NEILL: If you win, you get paid what you bid.

MS. ROSENQVIST: Get paid what I bid, okay.

MS. KELLY: I'd just like to respond to that briefly. What we have been hearing here is that -- and I've been hearing this drumbeat since two years ago, that the current regulated cost structure is not enough to induce people to build new transmission.

Now, when this first started, of course, we had dot com returns way up in the stratosphere and people were moaning and groaning and looking at interstate pipeline returns. And I think there was a major indication of rate of return going on, and that's where this incentive of rate design movement started. I don't think it takes that much to build new transmission frankly.

There was testimony on the Hill by an investment banking person who thought a steady rate of return of 11 to 12, maybe 13 percent would be enough to induce people to build risky new transmission. I don't feel like we have to give people the moon, and I would much prefer to see some type of discipline placed on those claims. One way to do that is to require people to say okay, how much would you charge to build this, and if you get the opportunity to own at the end of it, you know, that forces people to really take those desires for incentives and to kind of put them out in the light of day.

I'm suggesting that as one way to make people kind of come out of the closet on how much incentive it really takes for them to build.

MR. HEGERLE: I see Jolly and Steve waiting to jump in, and after that, I think we should probably take a break.

MS. HAYDEN: I guess as a follow-up question, and since I'm looking this way, I will use John as an example here. To make sure I understand where you're coming from, let's say that a third-party comes up with a creative solution that could, in essence, increase the ability to inject more megawatts into a region of John's system, and, you know, it's a third party idea and all that, and they so choose to pursue that. Again, this would be an added element subsystem to Southern's transmission system.

How would that -- how would that incremental capacity, you know, how would that person, that entity benefit from that idea and that investment of capital, in your mind? Even though it's Southern's system and any generator as a new customer or a load as a new customer that benefits, you know, how do you envision that working?

MR. O'NEILL: One thing you can do is get the transmission rights that those assets create. Another one is to essentially do what -- I think we have three or four filings here at the Commission for Merchant Transmission Systems. There's a lot of different ways you can approach this issue.

MS. HAYDEN: But you've got to get in this case Southern. Since it's their integrated system, they've got to agree that --

MR. O'NEILL: The RTO basically makes that call.

MS. HAYDEN: Excuse me.

MR. O'NEILL: The independent RTO makes that call.

MR. WHEELER: I wanted to respond to Dick's comment about the competitive bidding. In the West Connect process, it's a very bottoms-up, stakeholder-oriented review process that takes place at the RTO level on an annual basis that builds up from whenever the existing TO's plans are, whatever anybody else, be it a generator, market participant, somebody who wants a demand side management program or the like thinks would be best in terms of the overall regional plan.

That plan then gets vetted at the RTO level and adopted. Then it goes out for the opportunity to construct and own. It won't necessarily be the RTO that will own it, although it can be.

There is also the opportunity for the individual TOs to get the opportunity to construct and own because they very jealously guard their relationship with their regulators and citing authorities and the like in their area. But if they pass on it or it's one that doesn't go through their area, there's the opportunity for it to go out for competitive bid and be owned by anyone who is even not a TO. As I say, the RTO makes the ultimate decision on that in terms of what's best for the overall area.

I do have to disagree with Susan's comments about incentives. As a transmission owner, it is very difficult to get excited about building new transmission, given the uncertainty of both federal policy and state policy. You can't underestimate the difficulties in siting lines at the state level, particularly lines that start one place and end up at another that will not benefit the region that has most of the geography of the new line.

You couple that with retail rate moratoriums and rate freezes in terms of how you then recover, even if you get FERC approval for some incentive return and you get to include it in your FERC rates, if you can't pass that on to local native load customers who are taking service under bundled rates at state-regulated rates, it creates a very difficult landscape to think about transmission expansion, particularly transmission expansion that isn't directly related to native load.

That's why getting federal policy clarity, getting some certainty with respect to the recovery of investment at both the federal and state level, is very important.

MR. HEGERLE: That would also argue for getting everybody under one tariff as well?

MR. WHEELER: Not necessarily. If you mean everybody gets to go everywhere they want all the time, if it means just what it says, construction burdens on the system that would not be commensurate with any benefits that would be realized by doing it and wouldn't improve cost, in our belief.

MS. ZIBELMAN: I can add to that very briefly.

We were recently disallowed 50 percent of our investment in a line to connect the western and eastern interconnect because the Texas PUC felt they weren't going to get 100 percent benefit of that line.

To answer your question, it is risky. If we were a transmission-only company, that type of loss, which right now we're looking at about a $23 million investment, may be unrecovered and becomes a very significant issue. So that does argue, I think, for some form of federalization and a single tariff.

CHAIRMAN WOOD: What jurisdiction had the difficulty there?

MS. ZIBELMAN: The Colorado. And their reasoning was that this -- they couldn't be confident that this was going to be used and useful for retail rates. And so they weren't certain, even though from the planning process we felt like we had demonstrated it. My only point is that --

COMMISSIONER WOOD: For the record, you did to another jurisdiction down there.

MS. ZIBELMAN: Correct, who did approve it 100 percent on their site.

MR. ROSS: I'm going to be risky, but I think we might be missing the big picture here on the bidding process. I understand the traditional solutions, but that's not where I'm going. The single biggest -- potentially the single biggest RES constraint on the provision of electric service for 2002 as an issue is the interruption of the gas pipeline in North America.

I think that if you bid a solution that has come through a stakeholders' process, it may very well be not the transmission solution that the electric company came up with, but the bid solution may be the gas pipeline. It may be the dispatch of a generation must run contract that must run flows in the opposite direction of the constraint.

So I think when you open up a bid process, you instill creativity and innovative solutions, and you know what? It may not be wires in the air. It may be a pipeline. It may be a generation must run contract. It may be something else, and it may be cheaper than wires in the air.

I will close by saying on this comment, besides the fact that you meant to call on Commissioner Breathitt and you didn't, we studied in Virginia with AEP and shared an enhancement to bring a lump of coal into Virginia in 1988 and 1989. We filed the case in 1991. We went to trial in '92. We got a favorable hearing examiner's report in '92. That line -- we have not gotten state corporation commission approval to build that line yet.

It's not easy.

COMMISSIONER BREATHITT: Glenn, you were on such a roll, I said I would wait. Just to let you know I'm not a shrinking violet.

MS. HAYDEN: I was going to make a comment, but I won't. I would like to -- back to the statement that was made earlier about getting everybody on the rate under the single tariff that related to transmission and the risk associated with building transmission, and having been on the other side and very familiar with the line that Glenn was talking about, it does have a lot of risk associated with it.

I guess where I think the question was going or the thought was going or the way I interpreted, if you get everybody on the same rate, then is not the transmission company sitting there making economic decisions -- and by the way, I agree totally with Glenn's position, bid it out to the best solutions. We otherwise are thinking out of the box. There is always one way to tackle a problem, at least we sure hope so.

If a transmission provider is looking at this upgrade as how will I increase my throughput and, again, we set the incentives such that they have the incentives -- some kind of incentive base ratemaking potentially, will they not make the decision based on that and whether they're going to their state PUC, because they'll be looking at it from their balance sheet, is this a smart investment to increase the earnings on my -- to my shareholders.

MS. KELLY: I wanted to actually agree with Audrey on one or two limited points.

MS. ZIBELMAN: You can do it on all of them.

MS. KELLY: There's more than one way to address the risk/certainty equation, and one is to reduce the risk. I agree that when you go ahead and build substantial transmission additions and then can't get them in rate base because one particular state commission decides -- it's Tuesday and they don't like it or whatever their rationale may be, that's a problem. That's why I feel an RTO planning process is so vital.

I know a lot of people think it's the next five-year plan from Russia, the emphasis on centralized planning, et cetera, a bad idea. I think it's a good idea, because that's the only way you're going to get buy-in and give due process to people who might not want to see the transmission go from point A to point B.

You can try to get state commissions to see things on a regional level if they're participating in. If like an ISO says this is needed for the good of the region, that may go some way to overcoming what I call the petty, parochial concerns of landowners, of states. You've got to have this process to have buy-in.

CHAIRMAN WOOD: I think that clearly happened in New England when that group studied the Southwest Connecticut and then the first day of this year signing it, I think it was directly related to the state regulators up there.

COMMISSIONER MASSEY: We were in New York last week for this infrastructure conference, and we asked a number of the state commissioners that were there, would an RTO planning process that was credible help you make this decision in a way that's good for the region, and the unanimous answer was yes, it would help.

MS. KELLY: It gives them cover. May I just note that?

COMMISSIONER BREATHITT: I have even heard some parties suggest that the RTO in that planning process might even provide expert witnesses in a siting case to get it in the record. They might have to do that.

MR. HEGERLE: You've got the mike. Now's your chance.

COMMISSIONER BREATHITT: I know. I wanted to make sure this discussion was complete, because we're on a great roll. So I don't want to change subjects until we're ready to change subjects.

MS. ZIBELMAN: I agree with Sue. I think the RTO planning process will help in these circumstances. I also think that we're going to need to deal with the fact that getting the state PUCs to buy in is one piece of the puzzle, and then we need to deal with the next probably harder issue, getting the local communities to buy in.

With that, I think it's going to continue to take an awful lot of outreach and education that's going to go beyond the states.

CHAIRMAN WOOD: Susan, your two issues were the problems with the OATT directly today, energy imbalances, and --

MS. KELLY: I never did get to the second one at that time, but my concern is for people in the queue, either at the generator end or the load end and I guess the tag, you're it, theory of expansion.

MR. HEGERLE: Why don't we go ahead and take a 10-minute break now. We will start back up at 3:40 sharp, try to get started right away. We will start, whether y'all are here or not.

(Recess.)

MR. HEGERLE: Commissioner Breathitt has a question for the panel.

COMMISSIONER BREATHITT: That was a great session before we broke. It was very lively, and I didn't want to stop the flow of conversation to interject another question because I thought we had a good question going. I had one question for John Lucas, and Audrey, you had chimed in a little bit on the hubs, and Glenn, you mentioned, although you said you didn't have as much developed thinking. I wanted to ask the panel just generally if they thought we got the incentives right in order 2000 for what we were talking about before the break.

John, I was upstairs watching on the closed circuit for your opening comments. I got down here for Jolly and the rest, but you talked about transmission pricing hubs and that that was something that was new to your company and new to the region you were in. And Audrey, you mentioned you thought it was an intriguing idea, and Glenn, you talked about it, too.

Since I was not listening quite as carefully on my closed circuit as I would be had I been down here, I want you to talk about that a little more and say if they're different from the into Synergy, into TVA, Cobb, Palo Verde, those pricing hubs that we currently have that are organized, I guess, around NYMAX.

MR. LUCAS: I would be glad to. It's all premised on IPPs and network customers coming to me and saying the market has sort of established a hub trading into and out of Southern. We need transmission products to align with that.

So it's an idea that we, as the transition provider, have looked at and the product really is analogous to the network service product that we've been discussing in the interconnection ANOPR where you can have a generator come and say I'm requesting transmission service to the hub for my generator, and the evaluation we would do is very similar to network service.

We would try to evaluate, you know, the predominance of loads that that generation could serve, and most of those would be on the network. I think it would be difficult to carve out specific slices of interfaces and say that generator could always go across that interface, but I think if you look at could the evaluation be how much of the capacity of that resource could reliably serve load in the network, that would be our hub concept.

Now, if customers outside the region wanted to buy generation that was already at the hub, they could come and make a request, and assuming the interface capability was there, they could take it off at the hub. So the generator would have at least gotten the assurance that I can get it to the network. If there's a interface limitation and a new tie line needed, that customer is going to request to get the system upgraded. That's the concept.

COMMISSIONER BREATHITT: It's not so much a new way to price transmission as it is to price -- maybe a more rational way to price interconnections?

MR. LUCAS: Well, you could treat it as both, and I didn't finish the pricing piece. The John Lucas version of the pricing piece is you need to pay something to get to the hub, and customers needed to pay something to take it off the hub, but that not ought be at two times the systemwide postage stamp rate, but as an incentive component, it could be more than one times.

And, I think, getting to the hub would be analogous to the pricing concept that we would want to flesh out in the second phase of the ANOPR on interconnection.

CHAIRMAN WOOD: As incentive for what?

MR. LUCAS: Transmission providers to increase throughput, try to facilitate the market.

CHAIRMAN WOOD: For a TO?

MR. LUCAS: Yeah, a transmission owner that could get higher than just a postage stamp rate for use of the system.

COMMISSIONER BREATHITT: And help me understand, what is different about this system? Is it the current way that interconnection is done, it's more discreet than a regional hub?

THE WITNESS: Today, traditional interconnection requests are merely to connect to a facility, an existing transmission facility. The interconnection ANOPR, as you know, will explore how do you allow generation interconnections to, in effect, get the same status as a network resource that customers have today that they're already getting the output from? So it's just a way to say to, say, orient it to a hub and make sure it can deliver to an aggregate of loads.

MR. HEGERLE: Let's go right down the row here for responses.

MR. KELLY: I'm obviously hearing this for the first time, so I'm kind of running through this in my brain and trying to think of the implications.

In terms of flexibility to take power away from a hub, that may very well be a good idea for load-serving entities. I'd be interested in exploring that. Network customers, however, right now pay in order to have the right to take network service, a load ratio share of the entire cost of the system. If somebody's paying to get to the hub to serve our load, you know, it seems to me that there's money on the table there.

Maybe if that's going to be the incentive the transmission provider requests to provide that service, then y'all need to examine the justness and reasonableness of that request, but I do think that that -- you know, I'm trying to figure through the rate implications of that.

MR. HEGERLE: You will help us with that, won't you?

MR. KELLY: Once I form a viewpoint, I certainly will.

MR. HEGERLE: Jolly?

MR. HAYDEN: I think the question that Chairman Wood was asking related to the two times pricing. In the current paradigm, what the merchants are doing in order to get some of the benefits of this hubbing concept that we're talking about, in essence we're trying to assimilate the benefits of network service a little more flexibility. We will pay to come into a large area, control area, whether it be a Southern or Entergy, or take your pick.

So we pay an into point-to-point rate, and usually you're hubbing with whoever inside that control area, whether it be that utility, the load-serving side, or a municipal or a co-op, so you're paying them this hubbing fee, and then I'm paying an out-of rate. So in essence, I'm paying over two times their current point-to-point rate, in, out, and actually to park it.

COMMISSIONER BREATHITT: And that's what you're doing now? That's the current state?

MR. HAYDEN: That's one of the things that merchants do in order to try to capture some of the benefits that a hub, that the natural vertically integrated utility has versus everybody else. That's also one of the reasons why I think DENA has several control areas set up, a generator-only control area, because you get some of those benefits.

MR. HEGERLE: Doesn't the model in the Staff paper resolve some of the problem you're talking about in terms of the sinking and sourcing and what have you?

MR. HAYDEN: I think it probably does, and I guess basically you're -- this is going to be a question I throw back at John, but I think that's some of the flexibility that I would gain out of what you're proposing.

MR. HEGERLE: I got the impression where John was going earlier, was the Staff paper was almost too complex to get done right away, but something like his hubbing proposal was something he could do in the very near future.

MR. LUCAS: You've nailed it right on the head, and I apologize for not answering Duke's question as straightforward as I should have earlier. We ought to think about some set of transitional steps. To me, I think there are other products that could be done quicker and help facilitate better market access before you get to just a standard market design that says here's your market design, create.

To me, you've had markets that have developed based on that market and an Order 888 pro forma tariff. So it does happen. It's happening through RTO development. It happened with Seatrans. They will have a market design. I didn't want you to do anything to short-circuit a tariff that wouldn't work well with that market design.

MR. HAYDEN: One of the things that NERC has been trying to do off and on over the last few years was to eliminate the benefits of being a generator-only control area, and I would argue by getting everybody, you know, the flexibility and on the same tariff and all that, you kind of eliminate that, that commercial advantage.

As a question for John, within Southern right now, do you see natural hubs developing based on the physics of your system, i.e. the constraints; or I guess do you see yourself offering more than one type of hub service, i.e. if I want to group my units within a quadrant, in the case of Southern, or if I wanted to, systemwide, do it? And that obviously is going to have some ramifications on network upgrades and the like.

MR. LUCAS: I think we'd have to consider all of it, Jolly. I think you'd have to look at the network as a kind of aggregate network hub and then perhaps some subregional hubs, because we do have some stability problems and congestion problems in different quadrants of the system because of the huge amount of new generation we have trying to interconnect.

MS. ZIBELMAN: Just to respond to John as well, what I find intriguing about the hub concept is it starts to break the market down into what we're seeing as the markets develop. And it makes sense to me that if we're trying to create flexible network usage, that we design it around where these markets really exist and where people are trading back and forth.

With that, I think we can separate that maybe from the rate design issue and talk about how you design rates in a tariff to make sure there's fair compensation and you sort of appropriately classify the transmission facilities.

It seems to me with even that hub concept, particularly when you have a superregion like MISO which may have several different hubs in it, you can combine that with some sort of point-to-point so that if you're moving between hubs, you have that flexibility to do that, and that preserves, what I think is going to be very important for the Midwest market, which is having the bilateral transactions.

MR. O'NEILL: We have a working hub concept in PJM. Is this different from that?

MS. ZIBELMAN: If I can answer that, just from my perspective, it's the same, but the difference is that in PJM we have 2000 or so nodes, and in MISO, as I understand, we're talking about 40,000 different buses. What we're trying to do is break down MISO, I think, into markets that are similar in size to PJM that may be more rational to work with.

MR. O'NEILL: But it's the same concept?

MS. ZIBELMAN: From my perspective, that's the objective, is to figure out what's the rational size of the market to develop --

MR. O'NEILL: PJM, for example, will develop a hub -- if you don't define what you want the hub to be, they'll define it for you and put it into place, just like they testified to that.

MR. HEGERLE: In a day, he said.

MS. ROSENQVIST: PJM's hub is a financial model. I don't think John is talking financials.

MR. O'NEILL: If we got a new model coming, could you give us some description so we can look at it?

MR. LUCAS: We have some white papers.

COMMISSIONER BREATHITT: That's what I was trying to do, is flesh this out a little more.

MR. ROSS: Could you share the white paper with the full panel, John?

MR. LUCAS: Well --

MR. ROSS: John is a Southern gentleman. He always has been. I'll get it.

MR. HAYDEN: You know where he lives.

MR. ROSS: I guess not to try to set up a new definitional framework and certainly not to set up a new acronym, I think what the redraft of the Order 2000, somewhat on the fly, not offered as a criticism, but more as a what is happening, the institution is clearly evolving where ISOs once resided. I think as we were talking earlier about the level of expertise that exists within an ISO, to transfer the ISO to be an entity that can be the wholesale market institution, providing the right kind of energy products is a risk training and a risk analysis training that may not exist within some of the structure of the RTOs or ISOs.

So if you're looking at a day-ahead market or day market, I think the PJM model probably works extremely well. PJM, I think, has moved beyond that now, it sounds like in their testimony, that they can do a hub in a day. I'm not sure that's what John's talking about, but to get the right risk managers on board, in order to make sure that the products offered for energy services are the right products, and that there is a market for those products, to me, further defines what a hub is, the way John is talking about it.

If that is it, then I like the idea.

I would like to break it down farther. I've written four points down, that if you first internalize constraints in parallel flows -- which maybe Southern has done, we certainly have not done that in the mid-Atlantic states -- as John said, as you develop delivery service products to enhance trading operation, you've got to get the right talent at the ISO when you bring it to a wholesale market institution to make sure you're not doing something that is creating an unacceptable level of risk or gaining.

MR. O'NEILL: Can I interrupt? I don't think PJM's hubs create any risk for PJM.

MR. ROSS: I think PJM is an ISO, not a wholesale market institution yet.

MR. O'NEILL: Right. But you wanted to have the ISO taking risks. This is not a risk the ISO is taking. It's basically facilitating transactions. It's not in the market.

MR. ROSS: I will give you that. That's why I think the hubs PJM is talking about are not the hubs that I believe John is talking about.

MR. O'NEILL: Do we want the ISO in the business of taking risks?

MR. ROSS: No, no, I didn't mean it that way. I'm not talking about them taking energy titles. I'm talking about them developing a set of products necessary for risk managers to, like Jolly or others, then use those products to enhance -- what I heard in terms of enhancing trading is not just delivery products, it's contracts or a market for long-term contracts, short-term contracts. And they don't have to take a risk, they can simply be a facilitator.

I support the hubbing concept because I think what it does is balances the infrastructure investment to the market access. And that, to me, when you're taking power into and out of the hub, it needs to balance the infrastructure enhancement with the market access.

And fourth -- this is where I'll -- I'm not throwing out my support. I'm simply saying defining the hubs, and keeping up with them is harder than what PJM is doing, I think, and that is an issue that we need to wrestle down.

MS. FERNANDEZ: I guess when I was listening to this discussion -- I'm going to betray my gas background.

MR. KELLY: You go, girl.

MS. FERNANDEZ: PJM has totally financial transmission rights, and they have a western and an eastern hub that works within the financial mode. And you can go deliver to the western hub where there's a lot more generation, and you can go hub-to-hub and hub-to-market.

It sounded like what Glenn and John were talking about is something that's closer to a gas analogy where it actually is more like a derivative pool, or it's sometimes called like a tabs type service or sort of the way the IT feeder system works on Transco. It's station 65, all those pooling points you might have heard.

And that's basically where there's someone that is on the downstream, the one who is taking it to load has transportation rights, and someone that wants to -- various sellers that want to provide service to them, rather than the buyers, don't really want to buy at the wellhead, and the sellers really like selling at a liquid trading point, so that there's some either paper or physical point that's defined where the two can meet. And in the gas terminology, in terms of rate design, you only pay once and it's the downstream that does it.

Is that what you're talking about?

MR. ROSS: Actually, I will be the first one to jump up and say don't bring gas into this, because electricity's not gas. I'm okay with what you just said, but I will also say, if neophyte is the right word, I can say I feel like it's my wedding night and I'm going places I've never gone before.

MR. KELLY: That was not me, G-rated.

MR. ROSS: I need some time to really study what John was talking about.

MS. FERNANDEZ: I'm sort of betraying my gas background. I'm trying to figure out why if you have a truly financial system, why you need both. And the gas system, I don't really think of as a physical system, per se. It's more of a contract right-type model. I think that's why it works -- why it's set up the way it is.

MR. ROSS: I think where I heard John going is John's got a way to go and they're going to evolve something. PJM's already there. The other thing I found about PJM is they're innovative enough and willing to listen -- at least it seems to me they are, some people will gag -- my experience is they are willing to listen.

And if they want to -- if you want to develop a product or change a design of the market, you can show PJM it's worth sponsoring and you can convince FERC it's worth doing, then I'm not sure where John's going isn't where PJM could go. It may be a totally new concept, except for the gas analogy. I'm going to shut up there.

MS. FERNANDEZ: I wasn't sure if it was different means to the same end.

MR. KELLY: I understood it only pays once and load pays. But I would note, I was asked earlier by Chairman Wood about current problems under the current tariff. I understand the financial overlay, but since we serve load using network service, we have this thing about the reality of providing service on the ground. It's important to us.

We've had problems in the past under the designated network resources. We actually, a couple years ago, had one case that was brought to this Commission and resolved, and we were told we had to give a year's notice to change a resource or it wouldn't be considered sufficiently firm to study whether it could be delivered to our load. Y'all dealt with that in short order, and thank you very much for having done so. That's the kind of example of the implementation problems we have under the current tariff.

So to me, hearing the idea of as an interim step, you know, you can designate a hub as a network resource. That sounds pretty good, because that, in some ways, can avoid having to change designations of resources all the time, if they can bring it into a hub. So it's just kind of an additional flexibility that sounds interesting to me.

MR. HEGERLE: Steve, and we'll start back at this end of the table.

MR. WHEELER: Thanks, Mark. I want to sing my flexibility course one more time. Whatever the virtues of this hub approach or this new concept is here in the east, please don't automatically assume it will work in the West Connect area. Our primary hub or one of our most visible hubs is the Palo Verde hub and, as you know, has been an attractive point for a lot of new merchant generation that's being built around it.

We wanted to remove some of the congestion that associates getting that power to market. We came up with a very innovative solution of building a new switchyard and having you folks bless it as a common bus approach. And I think you were pleased that we were able to work out something with everyone that did that, that got more power to market.

But you need to realize that that hub has sort of network service to the east, because it serves Arizona and a lot of point-to-point service that goes west, and a lot of those lines -- virtually all of them are jointly owned, as is Palo Verde and the generating station itself.

That creates a lot of issues with nonjurisdictional entities who have ownership and control a portion of those transmission lines, that makes it more difficult to say all the service out of that hub is going to be network service. They either have statutory restrictions on who can use that line, they have tax issues with private use restrictions on who can use that line.

And so you have to be careful by just saying let's come up with this new concept of hubs, and we'll just overlay it on all the existing hubs throughout the west. So I would just tell you, you know, we're trying to work with what we think is a very good liquid hub there, but please be cognizant of its unique circumstances.

MS. FERNANDEZ: If you were a customer in West Connect, could you designate the hub as a network resource?

MR. WHEELER: You could get to the hub and then beyond the hub to where you were going in the network once you got to the hub. Beyond to serve load, that's a network resource.

MS. FERNANDEZ: I'm not sure I follow. Let's say I wanted to have the option of buying from multiple suppliers at a hub and you have several existing, it sounds like, physical hubs?

MR. WHEELER: Right.

MS. FERNANDEZ: Could I list those physical points?

MR. WHEELER: No.

MR. GILDEA: I guess I applaud the general concept that I heard from John and several people, of the hub. The hub is extremely important to trading whether it's in the financial world, the PJM today, or in the Synergy market today. The hub is our backbone. So to the degree we advance that hub in other markets, I applaud that. I think that's just a basic building block of really maintaining or revising the OATT.

When I get a generator connected in with kind of a quasi-transmission right to the hub, the only reason a hub is any good is if there's flexibility and ATC and all those other virtues around the hub, so I can switch resources out, the customers can find the lowest cost resource each morning. That all requires flexibility and requires efficiencies and business practices that aren't hidden in mass and comparability problems and all of that.

And so that type of structure, we need to fix a lot of those problems with moving energy around like on the point-to-point or on a bilateral basis in addition to creating the hub concept.

COMMISSIONER BREATHITT: You don't want to get to the hub and get stuck? You don't want to land in the Atlanta airport and have to stay there for five days?

MR. GILDEA: Yes.

MR. HEGERLE: As we move this way, we talked about trying to get to a standard mark design, and people made the comment earlier that it's too much, it's going to take years, years to get what you're actually looking for. Is the hub concept a starting point toward getting there, or do you have any other ideas how we might start getting there?

Masheed, when we get to you, I want to get back to your view as well.

MR. GILDEA: I think it would be a fine start, although as I said in my opening remarks, which I will supply in a written format here in this docket, I think there are a lot of small tweaks that we could add to the tariff and incrementally start approving. I think one of the big ones that wasn't in my list, that really needs to come sooner than later, is we need to get the persons that are making decisions on who gets access to the limited transmission and evaluating the transmission and the study requests, et cetera, to be a person that is not a player in the same market.

So I think until that happens, we've been approaching that task from the RTO, maybe as an interim step, we need something else on an incremental basis on some of the items until we have an RTO.

But in answer to your question, I think we need to attack or get more efficient some of the basic building blocks of moving energy on a daily or hourly basis in addition, and we need to do it before we have the RTOs.

MR. HEGERLE: Masheed?

MS. ROSENQVIST: What I was talking about was starting a tariff that maybe we are better off to just ignore the OATT as we know it to get a financial market. We all have tariffs in our regions that are written like an 888 OATT, but it's not really followed, only because we were all told don't deviate from it. So all the ISOs have filed these tariffs.

MR. HEGERLE: The words looked so good on paper, too.

MS. ROSENQVIST: Maybe we ought to look at it and say assuming financial markets like in the Northeast, what should this tariff look like. I tried to stay as closely to the OATT as I can.

For the network service, you definitely need a network service that, at the minimum, defines how the load pays and what kind of FTR auction revenues they would receive. How do you plan the system, much like the network service section of the OATT right now, that if you need a new interconnection of a new load delivery point, you have to go through the same study process and whatnot and follow that procedure.

For the point-to-point service, though, I ask myself why you would need it other than to export power out of that market, especially if you go to a postage stamp rate and generators are all connected within one region and they're all exported to another region. You may need that point-to-point reservation process at a minimum to pay for whatever might be needed, because the local market is not seeing the benefits of it.

So think about, the need for it, to export it at the same time as the fairness and pricing of transmission. Perhaps the higher up pricing could follow for export out of a market.

Point-to-point shouldn't be used to purchase FTRs. I understand that some tariffs say you can buy them as an auction or as a point-to-point service. What that would lead to is places where transmission is highly valuable and FTR auction prices are high. People jump into the queue and buy point-to-point service because it's cost-based. It creates a problem in a market that not everybody has the same access to this financial transmission right in an auction process.

MR. HEGERLE: So far what you've said, does it deviate from what PJM has? So far so good?

MS. ROSENQVIST: With the exception that PJM allocates the FTR, and I think it's fair to see an auction. You also have to deal with it if nobody buys it in the auction, what do you do with the additional revenues that come through the FTR revenues, the congestion revenues. You can probably allocate it back to the load that's paying for it.

Where I move away from the PJM model just so slightly is where I try to tie the ANOPR to the market structure, and that's where I started, as in will we have an ICAP market, will it be deliverable. If it is deliverable, isn't deliverability a physical right of some kind, and then that kind of merges into the network resource idea of the ANOPR. And if you roll all the costs in, if I were a generator and said you can have the Honda version of this or the Cadillac, I'd say I'd take the Cadillac if it doesn't cost me anything.

So how do you give the right signals in pricing -- in a generation standard procedure as well as perhaps not putting the last generator on the margin, which is Sue's problem, fifth one in the queue, pay 90 million.

So at the same time I heard some discussions yesterday where it talks about you have to start market-driven solutions as opposed to regulated central planning arrangements where you just go and upgrade the system as you need it. So I'm coming down to the ICAP deliverability issue of PJM.

We have also heard a lot of issues by New York and New England. End users and other entities that talked about we don't want a deliverability test, it costs so much, why don't you just, you know, let them sell ICAP if there is an ICAP market. This ICAP deliverability has been an issue, and it's going to become more of an issue when we get into the ANOPR and the pricing of it.

Again, at the risk of getting stoned by my colleagues on this side, I'm in a financial market model, like in the Northeast. Pick one standard for connection, and you can decide whether it's the plug and play New York, minimum connection in New England, or somewhere in between those and the ICAP deliverability, but set up an auction that the generators would purchase.

To the extent there is not enough capacity on the system to deliver all the generation -- for example, in Maine, Maine and southeast Mass are places where there's locked-in generation, and northeast Mass and southwest Connecticut are where there is too much load and not enough generation.

So, you know, if generation in Maine can't all be dispatched, should it be allowed to sell ICAP, and who should be allowed to sell the ICAP, and who should be allowed to self-schedule. What if everybody had contracts and they wanted to self-schedule and there's not enough transmission? What I'm suggesting is run an auction for self-scheduling rights or ICAP sales and, perhaps, not build all the way to the deliverability standard, and perhaps -- and you can decide where that range should be.

And the generators that really want to have self-schedule rights, they can bid in this auction process and buy those rights. You can take those moneys, again you can either credit it back to the customers that are paying for transmission, perhaps set up some incentives for the transmission company to increase those number of available capacity, and maybe they get to keep some of the auction revenue, some kind of incentive, or the generator can actually go and ask for a system operator to be billed and get the type of ICAP deliverability that is available in PJM.

When you set up a market structure that you buy those rights and it doesn't put the last generator on the margin, it says you pay for all this deliverability, it doesn't solve all of the problem. You still have to have the minimum connection standard, but it minimizes the debate. What you have to do immediately, every time you change from one structure to the next, you have to address grandfathering existing ICAP contracts, maybe don't require them until they expire, or require them to be buying, because you're going to change the financial agreements.

So you can set up some kind of grandfathering for those. It accommodates, perhaps, some of the rights the existing physical contracts have today that they like to have and keep, and Sue says don't take them away, it took us a long time to negotiate them. It gives us some sort of right for self-scheduling and playing in the ICAP market that it reduces the -- it preserves the value of those contracts to a greater extent than, perhaps, the Staff's proposal was accommodating, because it gives them some additional rights -- it gives them additional rights as compared to the Staff's paper, but perhaps not as compared to the rights they have in the contract, but it gets them closer to that point.

The revenues either could go to the customers who are paying for it, or in places like New York that you all heard last week, they don't want to build transmission, because the Upstate New York customers will have to pay for it while New York City benefits from it. In places like that where the allocation of cost is a major issue, these revenues could be accumulated to fund new transmission and, again, reduce the debate of who pays for it to some extent.

My last line is dealing with existing contracts as a whole, and my comment on that is I broke them down into two sets of contracts, contracts that have physical rights over the AC system and those that come with physical rights over the DC system.

The example is, say, Long Island Cable. The people actually buy physical rights -- physical rights is of great value. FTRs may be worth less once congestion is removed and flows change around. These systems are not cheap. So when people buy physical rights, they kind of like to hang onto them, because they need to -- they need them to supply their load.

Now, it is also physically doable, a system operator, it doesn't cause it any problem because it's controllable. So you don't have to treat it -- the system operator doesn't have to make a different decision trying to figure out whether there's loop flow or not.

Those issues are minimized in a DC system, and therefore, you can treat them differently and maintain those contracts, but perhaps do a secondary auction for potential use in case the rightholders aren't using it. Let them have the rights, but do advance auctions for secondary use, and you only give it to those entities that have bought it in those auctions if the original rightholder isn't using them in a real-time market.

On the AC system contracts, it's slightly different because it may cause the system operator some headache about let me look at the contract and see who has got the first call on this capacity. So you may, again, use the same concept as the Staff paper, but perhaps give them the self-scheduling and ICAP deliverability right as well when you sell on the auction, they can get the auction revenues or FTR revenues and whatnot. You could give an existing contract in a different category depending upon the characteristics of the system.

MR. HEGERLE: I want to get back, John, to the idea of transition, how we get from here to there, if you have any ideas.

MR. LUCAS: I guess going back to that question, is the hub a good starting point, I think it is, because the whole premise of it was based on transmission customers coming to me and saying can we put this type of product in place today with the existing tariff. I felt like we could.

I felt like it was analysis pricing, but I felt like we could get there. And the message from the customers said to me we have established a market hub. It is into and out of Southern. We want transmission to go with it. We are pricing our product into and out of Southern on a capacity and energy basis. We want a transmission set of service products that will go with that. So we had envisioned, you know, trying to do that much sooner than RTO implementation.

MR. HEGERLE: How long do you think it would take to get that started?

MR. LUCAS: I think you could frame the product up, you know, in a couple of months and look at some kind of filing.

CHAIRMAN WOOD: February 6. One of the things we did in Order 636 was, rather than try to dictate hubs, was make sure that nothing we did in implementing gas Order 636 would disadvantage the market's creation of hubs. This is kind of a no-brainer here for me.

MR. LUCAS: Right. Going back to Alice's question, do you need both? I don't see that you do, just sitting here thinking flat-footed today. It seems to me it's a way to make contract paths physical rights. Whereas, you know, a PJM-type system with FTRs and LMPs, that's a financial rights model, and they didn't get to that right off on day 1 when the pro forma tariffs were issued in '96. A market kind of developed and that's the way they chose to implement it.

I think you need to walk before you run in putting something like hub transmission and cleaning up some of the other things we talked about, where you clean up the issues, where point-to-point has to have a -- they don't have to have a contract, the network does, all the kind of confusion over rollover rights.

I think if you took those kind of baby steps and kind of did a swipe clean of the tariff and kind of updated it to current market conditions and then said, you know, as RTOs develop at some point in the future you'll need to have a standard market design that addresses the following, it seems like a reasonable way to go.

MR. HEGERLE: Susan?

MR. KELLY: Are you asking me the same question, interim measures until we get to RTO land?

MR. HEGERLE: Exactly.

MR. KELLY: I think all the comments that Mike has made, this hubbing concept seems like a good idea, but the one thing I would add, politically very difficult to do, I think really has to be done, is to get bundled native retail load onto the tariff right now. A huge amount of the transmission is going on behind the curtain. We've been talking about this for years. It infects CBM, ATC, impacts a lot of different areas.

I realize how politically difficult that step is to take, because many state commissions see putting the load on the tariff -- and I'm talking for rate purposes, too -- because it distorts competition on the ground to have it under the tariff, not for rates. I have clients experiencing that problem now. They all have to pay the same wholesale transmission rates. If you can do that one step, that would be a huge step forward.

MR. LUCAS: Can I just back up and respond to that? You may think there's a lot of transmission service going on beyond the curtain, but to the extent those customers are paying for those revenue requirements, I'm not sure there's an imbalance there. They've got some service, and they're paying for it.

MR. KELLY: I'm going to let Mr. Hayden answer that question.

MR. HAYDEN: I don't think my bladder will last long enough. I guess I'm going to start off with the following thing. Having grown up where I was with the GNT and we were serving co-ops and the like, the bottom line is -- back to your issue, people don't want a check in the mail for damages. They want deliverability.

And being an engineer in the background, I'm a little more physically bent than financially bent, and maybe that's my problem, but I am a big believer that as a result, in order for us to have a fluid, vibrant financial market and to allow me as a merchant entity to be as creative and competitive as possible to serve Sue and her client base, then, you know, one of the things to help get that financial market robust, we have to have a good solid physical delivery system. This is where we diverge from gas. There's no such thing as storage. Storage is in the shaft of the generator itself.

As a result, you know, one of the things Calpine has been trying to say -- Tom Castle drew me a triangle to get this through this thick skull of mine. At the base of that triangle is to get everybody on the same parity. There seems to be a lot of agreement across the boards. Then we get into the grandfathered agreements. As we've had the discussion today, in the case of SPP, when this discussion went down, it ended up only 10 percent of transactions were under the tariff. That doesn't work.

In kind of answering the statement about yes, as John said, there is -- the network customers are paying, you know, for their embedded cost of service, but as Sue brought up earlier, there was -- there is some serious, you know -- it's a different tiered system. There is advantages that they have over -- that the rest of the market does not have. There is still an access issue of what's left and how it's allocated and the CBM issue. I've already stated that opinion.

So, I mean, that is, to me, a foundation. We go out of that right out of the gate, which is a big one, politically it's a big one, but that's going to get us a lot farther along. Obviously, the next step is this independent transmission companies, the RTOs and all, and the point that several of us made, they don't need to be -- they don't need to have load-serving obligations. They're there to provide transportation services.

A customer is a customer, regardless of if it's in an area to serve a municipal or a co-op, across that area or to go out of that area. That's all they're there for. Obviously, we're moving along with that as we speak.

Then from there back to John's comments -- and I agree with them -- this standard market design is an ongoing evolving process. As much as we wanted it yesterday, you know, you're not going to get it all overnight, but I would argue if you tackle these first two things, you're going to get a major bang for your buck. The hub concept, the physical hub concept is obviously something that you could use to bridge, and ultimately we get all this worked out, and we can -- the need for it may go away.

But as I said before, marketers, generators, and merchants, we have been contractually creating, synthetically creating these hubs for some time now, because we know the benefits that it brings us, and we've had to pay a serious premium to get there. Which, by the way, affects what I charge when I make an offer to Sue or her clients on providing services.

COMMISSIONER BREATHITT: Would the premium go away if we figured out a way to do these in a more organized, formal way?

MR. HAYDEN: By the way. I will make a comment. John made a statement we wouldn't be charging twice, but we want some incentive. You're thinking right, exactly. Like I said before, I'm currently paying into in that example and out of. So I'm paying two times plus a hubbing fee to the entity who can technically hub for me if I don't already own generation there. So yes, you can definitely squeeze that down substantially.

COMMISSIONER BREATHITT: That's good. That's a good thing.

MS. ZIBELMAN: This is a lot to digest, and I was thinking about his last answer. I think that in terms of that -- and the hub discussions today has been very helpful to me today in illuminating how we can work through this process.

The differences in what I'm trying to accomplish when I think about the hub concept is how do I improve physical delivery in the Midwest and deal with the fact that we're trying to move from a different construction to another form of construction. I think one way of doing this is not a leap to the whole end state with more of a financial right is understanding and getting a better handle on what facilities we really need to get built to create -- to reduce the constraints in the system and to allow for much more of a netted work use of the system.

I think the hub concept can get us there, and I'm interested in seeing the white paper and thinking about out of that, then, how would you create the hubs to get to that end point. But I am thinking in terms of more physical delivery than the financial status.

The other question I have is once you do that, it also allows you to start thinking about the financial consequences of the new investment and who is going to pay and what are the reactions. Now, part of the dilemma, I think, we all have when we look at is there is a real advantage of getting all load on the tariff.

The question is, if you get all of the load on the tariff, meaning the traditional retail customers, but you leave the grandfathered load off, what are you saying to the retail customers who are now on the tariff and they'll look at the grandfathered agreements and say they have a distinct advantage that I've lost? So I think we can't deal with one problem unless we deal with the other.

MR. HEGERLE: So all is all?

MS. ZIBELMAN: There's always a question of what are the economic consequences of doing one or the other. For example, suppose we say to the bundled load today, you no longer have access to transmission, you have a right to get some option of some FTR rates, but you, the grandfathered load, have true access to transmission. To me, that creates a discriminatory impact that I'm assuming would be unintended.

So as we're dealing with the problem of what we're going to do with network load and what the solution is, I think we need to think of the downstream consequences when you're creating, again, two different classes of customers.

MR. O'NEILL: I'm trying to understand this in the context that I understand standard market design, that the standard market design, markets that we have operating today, don't sell financial rights that aren't essentially physically feasible, so that the issue there is that when they sell you a financial right, you can take delivery.

Now, there may be some people who are willing to outbid you and you may voluntarily give up those rights to accept revenue, but you don't have to. I'm worried that we have this -- that we're trying to decouple the physical and the financial when, in fact, it's not necessary and the PJM rights only are sold if they're physically feasible.

MS. ROSENQVIST: PJM, the standard market design that we were talking about, you buy the FTRs, but it's only a financial hedge, a financial tool. You don't get the right to schedule anything. Your right to get scheduled on comes based on your bid.

MR. O'NEILL: But if you schedule a transaction that's equivalent to your financial rights, it will actually be executed, and you will have to pay nothing in terms of transmission service.

MS. ROSENQVIST: Whether you get scheduled or not comes from self-scheduling or comes from your bidding behavior. You may not get dispatched at all.

MR. O'NEILL: You're disagreeing with the way Andy Ott describes the system.

MS. ROSENQVIST: The way I understand the FTRs is it's a financial hedge in that you're moving power in a congested direction. I can go -- as an end user customer, I can go buy --

MR. O'NEILL: But as Andy Ott explains it to me, if you have that final transmission right, you can schedule a physical transaction that's equivalent to that transmission right, and it will be executed.

MR. KELLY: That assumes you can get the FTR for the path, and that goes back to the simultaneous feasibility that they're not going to sell more FTRs.

MS. FERNANDEZ: Can't you also self-schedule, even if you don't have the FTR and you agree to pay whatever congestion charges there are?

MR. ROSS: Yes.

MR. O'NEILL: I don't know why we're having disconnects between physical and financial when that problem has been solved.

MR. HAYDEN: It's been solved and a tight pool has been in existence for 30-plus years, and that's the point I was making earlier, Dick, that until we get the physical model functioning fluidly, we're going to have a hard time getting that to work properly. We've talked in theory --

MR. O'NEILL: Is this like Scotch or wine? Do you have to age this process to make it work?

MR. HAYDEN: No.

MS. ZIBELMAN: Dick, I would answer the same ways. I think the concerns would be this: The people who are used to having the physical transmission rights, if they're going to give them up for financial, how can they be assured they're going to be in the same economic position that they were and the market isn't going to work that way simply because today we don't have a grid that was designed to necessarily accommodate the transactions that people want to use it for.

MR. O'NEILL: Let me give you a specific example. There apparently are some physical rights out West, that the way the California ISO scheduled its system couldn't be accommodated as financial rights. The ISO is now proposing to do something different that essentially allows the scheduling process to take place within the financial process so that they have taken the formerly physical bilateral transaction rights and allowed them, by rescheduling, to be converted into financial rights and not to take away any of those rights.

I believe you could schedule up to 20 minutes before the hour, but if you put in a process that basically subsumes that, then you can get the exact same or better rights.

MS. ZIBELMAN: If I can just sum up, I think the concern -- well, the concern we have in the Midwest is that theoretically you can get to the same point, financial versus physical, in terms of your access and use of the system, then it should work. The concern that we have is today we don't have a system that works like that.

So the issue is, how do you get there first and what do you want -- and not be put in a position where you give up something before you know what the replacement is?

MR. O'NEILL: I agree with you.

MS. ZIBELMAN: The idea of moving to an

evolutionary market and also making sure you have the right signals for the investment will give a lot of comfort to people.

MR. O'NEILL: That seems to be my point. We're regressing rather than going forward. We want to separate the physical from the financial when there are markets that have solved that problem.

MS. ZIBELMAN: And again, I think the concern is they solved it after coming from the tight power pool where the physical was largely --

MR. O'NEILL: Can you not learn from that process?

MS. ZIBELMAN: I think we can learn from the process, but you have to give us an opportunity to build the transmission so it can work like that.

MR. HEGERLE: You're saying the backbone's not there yet?

MS. ZIBELMAN: Exactly.

MR. HEGERLE: Glenn?

MR. ROSS: I love my job. I actually understood all of this. I just want to bring in on Dick's concern -- and I'm not trying to reinitiate the debate --

MR. HEGERLE: But you're going to.

MR. ROSS: No, I hope I don't. Physical hubs work in gas. We know that. Do physical hubs work in electricity? I don't know that, and I want to be sure my colleagues who are listening to this behind me and out there understand that this is a proof of concept that did work in a tight power pool where there were huge amounts of generation, 35 percent reserve margin. It's different with a 12.5 percent reserve margin world. I don't know if it will work.

By the way, the comment on the walk before you run -- and this is harsh, but I really mean this. It's okay as long as it isn't crawl before you walk, because the Southeast hasn't exactly run anywhere in this process. So I am very interested in walk before you run, and I'm sorry, John, but I think we need to deploy wholesale market institutions rapidly. I don't think we're doing it fast enough.

At the October 17th RTO week, I read into the record -- and I will do it again, because I think it's very important -- "transmission service will be used by merchant generators not designated as the network resource to move power to a trading hub. Conceptually, this may provide a mechanism for generation to sell into a liquid market. The ideal trading hub has a correlation to a commodity market. For example, at least one ISO has a hub -- I don't know if we talked about that -- that is an aggregation of several locations, that is, a financial product that everybody uses for trading.

"But the generators can still bid into the pool, and the generator takes any financial risk or benefits between the aggregated price and the actual generation bus price. Then the loads would take any redispatch risk at LMP in the event of any system imbalance or congestion. Generators must have the capability of moving their product to market and must have the capability of hedging out long-term products into a liquid market."

I think that's where we are with this process, and I read it only to make sure I got it in right. I will file comments. So if I didn't get it right, it will be okay. Transitionwise, Mark, I don't think we can do what you say, and I hate to say that --

MR. HEGERLE: I'm asking for what you think we can do.

MR. ROSS: Many states have cap rates. My state has cap rates until July 1st, 2007. To avoid a cost shift, it may occur. I think we need to be cautious about how we proceed with the voluntary negotiation of contracts. I have transmission only, not bundled contracts, transmission contracts with power agencies in North Carolina that have 10-year notice provisions. Even if we started the notice provision now, I don't think that's the time line --

MR. HEGERLE: That's crawling backward, isn't it?

MR. ROSS: Yeah, it could be, but I want all loads to take service under the OATT. Maybe we have got to do some sort of negotiation. If we synchronize this transition to rate caps whereby we don't have trapped cost, you try to enter into voluntary negotiations. But in the event you can't, maybe what we do is you have no renewals beyond the expiration date, you take what's in the contract, and you give notice today, although it isn't my notice to give. It's their notice to give in an effort to move all load to the OATT.

MR. HEGERLE: So you transition as contracts expire is what you're saying?

MR. ROSS: I think you have to, but what you do is for contracts with nonstandard terms and conditions, meaning not the new market standard, and you're talking in the questions how you place them under a standard tariff and how should the level of service in those contracts be honored, maybe what you do is the benefits of the new market design don't transfer to the individual who is unwilling to unbundle their contract. It may be an incentive to bring them to the table to voluntarily renegotiate their contract. Maybe they would pay pancaked rates until such time they permit that negotiation to go forward.

MR. HEGERLE: Susan's all forward for that idea. I can tell.

MR. ROSS: Why should a person be able to pick and choose what they want? They don't wanted to unlock their old contract, and they want to get all the benefits without having to pay the cost associated with the cost shifts. I'm not an advocate of pancaked rates, but I am not an advocate of aligning someone to get free-flowing benefits as a free rider.

MR. HEGERLE: The key there is to make sure they are getting the benefits so they do really want to switch over.

MR. KELLY: Can I address this issue? I know it's 4:45, so I want to be quite brief. I wanted to note that in saying that we wanted all loads on the tariff, I don't think we're asking for existing contracts to have some kind of super priority over bundled native retail load.

Right now it's the exact opposite, and the NSP decision from the 8th Circuit is what makes that abundantly clear that that's the case. We need to get more parity so that we don't have this ah, but bundled native retail load trumps everybody for purposes of TRL, et cetera, et cetera, because we have state obligations, and all wholesale customers must have second class status. I think there are definitely difficult transition issues when it comes to existing contracts and the contract that Glenn noted is one of them.

I don't think that 30-year transmission agreements are going to be allowed to run for their entire term. There's going to have to be a compromise. One of the things that will make that compromise easier is if you have such a wonderful, fine transmission service that people will want to get on it. I think penalizing them and kicking them in the teeth for wanting to stick with their current contract, that's going to invite -- that invites court appeals and litigation, which you said in Order 2000 you couldn't have that. That's why it had to be voluntary.

COMMISSIONER BREATHITT: In RTO West, we heard that there would be a voluntary --

MR. KELLY: A catalog.

COMMISSIONER BREATHITT: Yes, but that the new service might be attractive enough that parties would voluntarily relinquish their contracts.

MR. KELLY: I was very interested in Steve Walton's presentation of the concept of the catalog of rights. We'll all be looking forward to March when this filing is made. I think there are ways it can be dealt with, but my point is to make sure that we understand exactly what those rights are. We have wholesale contracts. It's known what those are, what our rights are, whatever they are. But what we don't know is what is not currently reduced to contract, and I think this -- putting all loads on the tariff requires everybody to kind of show what it is they think they really need.

MR. HAYDEN: Quickly, it's interesting, '97, '98 when PJM went -- from the market perspective went to LMP, before that occurred everyone was selling in the wholesale market what we called on the 500, and there was definitions of what that meant. Well, when we converted to LMP, which, I think, was April -- I don't remember exactly -- April 1st, appropriately, we all of a sudden went from on the 500 to West hub.

Now, everybody that was out there, they had long data contracts. Some of them five years in length that were on the 500, and all of a sudden everything was trading West hub. Now, there was this disconnect. We had a couple of choices, but the bottom line, the market quickly adapted. They developed and monetized what that delta in value was, and people converted their contracts. It didn't happen all the same day, but it did happen, and some, their contract terms were close enough to expire, and they let them ride out.

And again, I think -- your point, we can't let these 30-year contracts go for 30 years, but, you know, we've got to suck it up and, you know, we weren't sure if this LMP was a good thing or a bad thing. We were kicking and screaming a little bit, a lot of us, but we didn't have a choice.

Along those same lines, to the bit about this evolving versus crawling before we walk, I agree. This is not my primary job. While this is stimulating to me, it's not what I want to be doing. I've been doing this off and on for way too long. There was a statement made back in the seams conference in the fall by SFPP that things are evolving. I think the comeback was evolution takes millions of years. We don't have that kind of time.

I see this transition between where we are today, where we get the rest of these RTOs up, and where we really develop some of these liquid financial products. It should be, and it has to be, directed from the -- unfortunately from the top down, I think, in a lot of ways. It should be a short transition of a couple of years. It has to be. In the meantime, over the next several months, we could probably get a locality of bang for our buck with some of the things that we're talking about here.

MR. O'NEILL: No one's preventing people from filing things that you can put in place in the next couple of months. The idea is that that doesn't slow down the overall market design.

MR. HAYDEN: I will tell you this, it's probably been four years ago that I was in Birmingham and I was having this discussion with John about offering a hubbing service. It took Southern that long to buy into it, I guess because a lot of other people started knocking. I had these discussions with all the providers and merchants. It's not just from my various roles but all the merchants.

MR. O'NEILL: The hubbing service in PJM has no extra fees; right?

MR. HAYDEN: You're selling into --

MR. O'NEILL: You said you were paying hubbing fees and entry fees and other fees.

MR. HAYDEN: Someone has to be able to absorb that generation. So in a vertically integrated utility that is not a pool, you had to go to the merchant load-serving side of that provider to get them to pay -- you pay them a fee.

MR. O'NEILL: So they were redispatching their system in order to accommodate your transactions?

MR. HAYDEN: In that scenario. Whereas, with a pool, you have a pool where you can buy and sell in the spot market with.

MR. ROSS: Just a quick data point on what Jolly is saying. The mark-to-market book we had on April 1st, the day of transition is why, I think, transition costs you need to be very careful about how costs flow, shifted from sellers' choice to buyers' choice off the 500, 140 million mark to market that day was the impact to me.

I had incentive to renegotiate those contracts on that day. It was very painful. We had a guy that was in Europe. He got called back off vacation, because he's the one that set up the contracts. It's painful, and you need just a data point. Jolly's right on the money. We can't do instant transition.

MR. O'NEILL: Was this under the early PJM market design?

MR. ROSS: This was on '96-'97.

MR. O'NEILL: Where PJM came in here and said choose and we chose and it collapsed?

MR. ROSS: I don't know about that.

MR. HAYDEN: I'm not sure what time line you're talking about. I go back from '94-'95, it was basically like he said, on the 500, sellers' choice. Again, when we transitioned --

MR. O'NEILL: That was the two-zone model, I think, the PJM two-zone model?

MR. HAYDEN: I don't think it was a two-zone model.

MR. ROSS: I don't know.

MR. HAYDEN: I think it was before any proposal came in here and said we're going to, and ultimately it was LMP.

MR. HEGERLE: We're about out of time here and Steve did not get to answer my question.

MR. WHEELER: I wanted to talk about the transition of everybody onto the RTO tariff. What I've been hearing is certainly, at least it's Staff's desire to have that done and everybody agreeing that's a theoretically perfect solution to a variety of problems, and I just want to remind folks, that at least in our area -- well, the supposition of this theory is you're either going to browbeat or incent people who don't have much of a choice but to go along with the program, and you're trying to get them to go along with a relatively happy face.

We have a situation where we have the nonjurisdictional entities who believe they do have a choice, which is not to participate at all, and comes at the expense of either giving up their contractual rights or what they think is a violation -- or complying with something they think would violate their statutory obligations.

We have a contract that has transmission rights, has wholesale sales, has coordinating services. It has a division of territory. Since it's been blessed by state agencies, is still lawful. It has us serving people in their territory, they're serving people in our territory. If you start telling them that the transmission portion of that is going to be unwound, even if they said okay, let's just figure out how we make everybody economically whole for that, even if they said that, the prospect of trying to unwind that contract and put everybody in the same position they would be with respect to everything else is a daunting task.

What they are telling you is they don't want to have to do that. WAPA on the western side is saying we don't want to do that either. You do have to recognize that there might have to be a second best or third best thing to that issue. Where we get the participating TOs to agree to convert, we get the ones who don't have to agree, we have a best efforts clause to renegotiate, and then we've got some other revenue enhancement provisions. You might have to accept a less-than-perfect solution to that issue, and I urge you to keep that in mind.

MR. GILDEA: Can I make a quick point? To add on to what Jolly was saying about how important the hub is, we experienced last week with the start-up of MISO a rate increase of, about a 50 to 60 percent rate increase. We're still trying to do a hub, even with that size of rate increase. I don't want to go down that road, but the point I'm making, that fundamentally the concept of a hub in a physical market and financial market is just a fundamental base in which the market operates today. It shows you how important it is, even when you have an inefficient rate increase like that, to do a hub transaction and why we're still doing it.

MR. HEGERLE: I'm sorry to call this to a close. I think we've accomplished a lot. We could talk a lot longer as well. I want to thank you each for coming here today and expressing your views. I encourage you to file your comments. Several of you said you had proposals. I would love to see those if you have those.

MS. FERNANDEZ: Tomorrow, we're going to start at 9:30 again. So we'll see a number of you then.

(Whereupon, at 5:00 p.m., the technical conference was adjourned, to be reconvened at 9:30 a.m., on Thursday, February 7, 2002.)